

GAS CURTAILMENT RISK STUDY

Prepared for

The Electric Reliability Council of Texas

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1.0 Executive Summary

This study presents the risk of gas supply curtailment to electric generators within the service region of the Electric Reliability Council of Texas (ERCOT) over a 1-Year, 5-Year and 10-Year time horizon. It reviews historical incidents of gas supply curtailment experienced by ERCOT's generators, examines the natural gas infrastructure serving these generators and assesses the risk of gas supply curtailment on a probabilistic and a fundamental supply/demand basis.

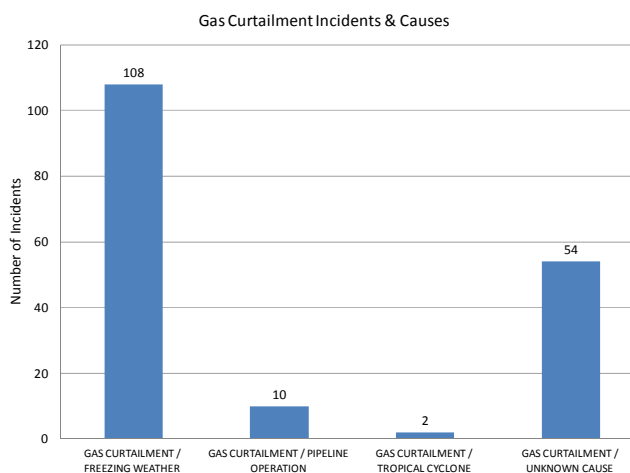
Curtailment was defined for the purposes of this study as the loss of normally expected gas delivery as a consequence of supply or transportation interruptions caused by weather-driven, contractual or operational issues.

This study considers the physical capabilities of the natural gas infrastructure in serving electric generators rather than the contractual arrangements to serve electric generators with natural gas. Although there may be financial implications to procuring the gas supply needed, natural gas service is generally available to electric generators subject to the regulatory and physical constraints of the system. Further, studying contractual agreements which are subject to commercial negotiations and change through time, does not allow for a longer term view of the risk of natural gas curtailment to electric generators which is better captured from the perspective of the physical limitations of the natural gas infrastructure in serving the needs of electric generators.

This study does not include or consider mitigating measures that have been or can be incorporated to reduce the risk of gas supply interruption for power generators. Therefore, this study takes a conservative view on the risk of gas curtailment to electric generators. There have been significant changes in the gas industry over the last 25 years, specifically, the pipelines typically no longer own the gas they transport and deliver, and there is an increased use of gas storage as a physical hedge against both supply and pricing volatility and to ensure deliverability. Combined with the greater liquidity in the natural gas market, in reality, when natural gas supply or delivery is impacted, the redundancy and interconnectedness in the natural gas market generally provides consumers (including electric generators) with alternate sources and routes for natural gas supply to partially or fully serve their needs. Pipeline linepack, natural gas storage and displacement of supply from other markets could all contribute to mitigate the risk of disruption of natural gas supply to electric generators within the ERCOT service region that are presented in this study.

Historical curtailments data recordkeeping is limited

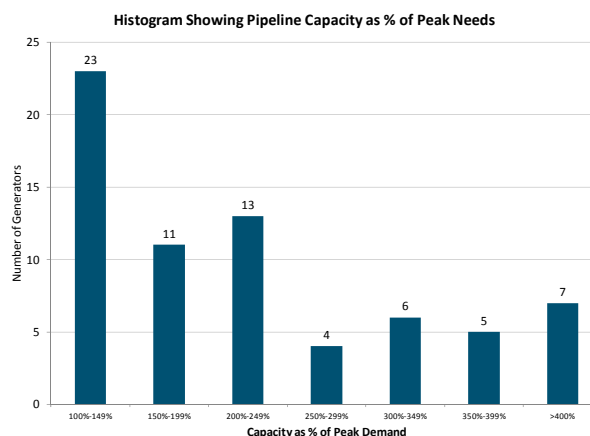
This study examined historical records for gas supply curtailment from various sources including ERCOT, the National Energy Technology Laboratory (NETL) and the Railroad Commission of Texas (TRRC) and found severe limitations in capturing information about incidents of natural gas curtailment to electric generators. The leading cause of the gas supply curtailment incidents identified was freezing weather with existing TRRC



regulations and/or pipeline contractual provisions contributing to gas supply curtailments to electric generators. Pipeline disruptions and tropical cyclones were inferred to have caused the other historical incidents of curtailment that were reviewed.

ERCOT generators demonstrate reliability and redundancy of natural gas supply

This study conducted a survey of electric generators within ERCOT’s service region to assess their access to natural gas infrastructure to serve their gas demand. Based on survey responses, ERCOT’s electric generators demonstrate reliability and redundancy of supply through their interconnections with multiple pipelines and access to a level of capacity that is well in excess of their peak natural gas needs.



60% of survey respondents (corresponding to 51,550 MW of nameplate capacity¹) indicated interconnects with more than one natural gas pipeline. All the survey respondents that provided sufficient data to make an assessment of adequacy indicated access to capacity in excess of their peak needs.

Natural gas pipeline infrastructure is sufficient to meet projected needs

Natural gas pipeline infrastructure serving ERCOT generators was found to be adequate to meet anticipated peak demand during the analysis period in the scenarios analyzed.

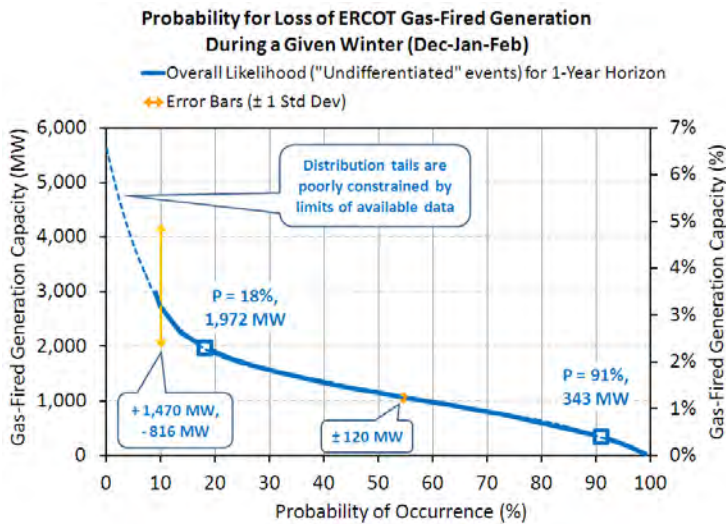
¹ The nameplate capacity is inclusive of generation capacity that is part of Private Use Networks which generally serve their own industrial loads rather than selling power into ERCOT.

Although there is potential for isolated incidents, the fundamental supply/demand analysis undertaken in the study indicated the robustness of the natural gas pipeline infrastructure in meeting the needs of electric generators within ERCOT, even in the presence of strong competing demand from other markets and sectors.

Risk from Freezing Weather - 18% probability of having 2000 MW of capacity temporarily unavailable due to gas curtailments

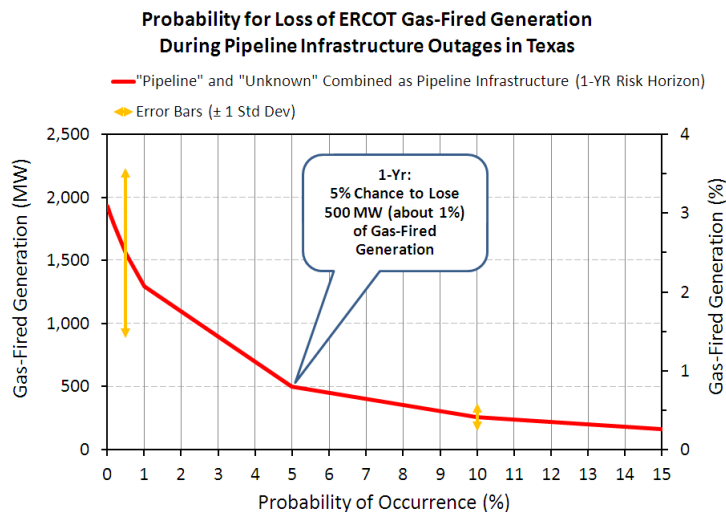
Risk assessment, based on historical incidents of curtailment, indicates that in any given winter, there is an 18% probability of supply disruption from lack of gas supply or contractual/regulatory defined curtailment impacting about 2,000 MW generation capacity and about 90% probability of impacting about 350 MW.

While freezing weather is the most impactful of the risk factors considered, the probability of gas supply curtailment due to freezing weather projected forward should be viewed together with associated mitigations - namely, increased thermal protection of wellheads against freeze-offs and the priorities and revision of contractual curtailments initiated by freezing weather. Both wellhead thermal protection and alternative contractual provisions offer opportunities for assuring greater reliability of gas deliveries during cold winter events.



Risk from Pipeline Disruptions - 5% probability in the near-term of having 500 MW of generation capacity temporarily unavailable

Risk assessment of pipeline disruptions based on historical incidents of curtailment indicates that there is a 5% annual probability of losing 500 MW as a consequence of gas supply curtailment due to pipeline outages. Although risk assessment assumes that the entire amount of curtailed gas was required for power generation and no alternate

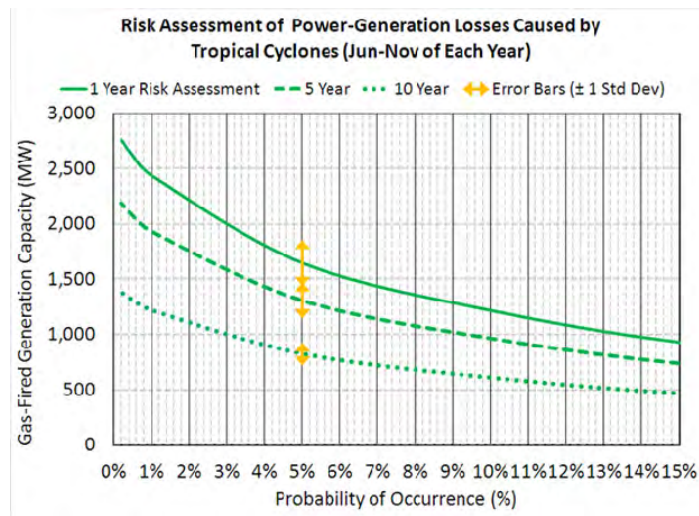


supply was available, redundancy in pipeline capacity serving generators can reduce exposure to gas supply curtailment from pipeline disruptions.

Risk from Tropical Cyclones - 13% probability in the near-term of having 1000 MW of generation capacity temporarily unavailable

Compared with the total volume of gas required for ERCOT power generation, the proportion of gas obtained from Gulf of Mexico (GOM) offshore production is small with less than 5% of the total ERCOT gas consumption depending on GOM

production. Therefore, tropical cyclone impacts on ERCOT’s power generation are relatively small. For perspective, on the 1-Yr horizon there is a 13% risk of 1000 MW generation loss from tropical cyclone.



Conclusions & recommendations

Data availability placed constraints on understanding and analyzing historical gas supply curtailments to electric generators within ERCOT’s service region. Increased coordination between natural gas and power industry regulating agencies could help ensure improved cross-capture of information as the role of natural gas as a fuel source for power generation continues to grow. If ERCOT is expected to monitor fuel impacts on the reliability of the electric grid, better data capture of curtailment incidents is needed.

Some specific recommendations are listed below:

- ERCOT Operator logs were the most complete source reviewed in the study of incident data on natural gas supply disruption experienced by electric generators within ERCOT. It was observed that capture of natural gas curtailment incident information would be more complete and accurate with greater training of ERCOT operators to improve recognition of, and familiarity with, natural gas pipelines and utilities serving ERCOT’s electric generators.
- This study included a survey of gas-fired electric generators within ERCOT’s service region to assess their experience with natural gas supply disruption. It is recommended that standardized categories of gas delivery issues should be included as a regular report element in the annual reporting by generators to ERCOT. This will allow ERCOT to track and assess any trends associated with natural gas supply disruption to electric generators and to develop risk mitigation plans if a trend reflecting increasing disruption to electric generators is observed.

- This study recommends continued coordination between ERCOT and the Railroad Commission of Texas (TRRC) to facilitate better data capture including development of communication pathways and reports for gas-delivery incidents affecting power-generation facilities.
- In addition to cost considerations associated with the decision to contract for firm or interruptible gas service and /or have dual fuel supply, contractual agreements that require curtailment of gas supply to generators or mandatory curtailment policies as defined by the TRRC may inhibit a power generator's ability and motivation to acquire firm gas supply. Review of these agreements and policies could help determine whether new policies or regulations are required to increase the reliability of ERCOT generation.

2.0 Introduction

The Electric Reliability Council of Texas (ERCOT) commissioned a Gas Curtailment Risk Study to evaluate the risk of natural gas supply disruptions to electric generating stations within the ERCOT administered portion of Texas.

During the first week of February 2011, the Southwest experienced extremely cold weather with temperatures falling by as much as 50 degrees over an eighteen-hour period in various cities in Texas. This extreme cold event saw low temperatures in the Dallas-Ft. Worth area dipping to 13° F which, according to our probabilistic analysis, was an event with a winter-time daily probability of less than 1%. During the first four days of February, 210 individual generating units within ERCOT's service region experienced disruption of their normal generation operations due to a variety of factors. The scale of generation loss led to controlled load shedding that impacted as many as 4.4 million customers² during the event. A majority of the generation losses experienced occurred due to problems related to plant operation including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, and blade icing. Extreme low temperature events in 1989 and 2003 similarly created conditions resulting in loss of generation in ERCOT. A FERC-NERC investigation found that, although the generation loss associated with these extreme weather events was not primarily driven by gas supply curtailment³, natural gas supply was impacted as a result of weather and contributed to the loss of generation.

By fuel type, about 38% of ERCOT's annual average generation is currently accomplished with natural gas.⁴ Gas-fired generation capacity within ERCOT is projected to increase by over 15,000 MW in the next 10 years. With natural gas' share of electric generation within ERCOT being poised to increase to 50% over the next 10 years and beyond, it is important to understand the risks faced by electric generators due to potential disruptions in natural gas supply.

This study is intended to increase ERCOT's understanding of the risks of generation loss from gas supply curtailment in the future and to consider potential mitigation measures that ERCOT can pursue to reduce risks arising from these curtailments. The study is also intended to assist ERCOT to objectively assess the costs and benefits of planning operations for mitigating gas supply curtailment risk to its electric generators.

The scope covered by this study is summarized below:

² *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*, Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC), August 2011.

³ It was stated that "For the Southwest as a whole, 67 percent of the generator failures (by MWh) were due directly to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like." (p. 8). *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*, Federal Energy Regulatory Commission (FERC) and North American electric Reliability Corporation (NERC), August 2011, 357 p.

⁴ ERCOT (2011b) Data file: GenerationByFuelType_2002-2010.xls.

http://www.ercot.com/content/news/presentations/2011/GenerationByFuelType_2002-2010.xls

- Deliverable 1 – Review past natural gas interruptions impacting electric generation for insights.
- Deliverable 2 – For pipeline systems that serve generation, survey pipeline physical limitations to providing natural gas to electric generation in ERCOT.
- Deliverable 3 – Review scenarios in which ERCOT natural gas supply to electric generating stations could be significantly limited, including conditions of severe cold temperature combined with high wind speeds. Calculate the risk (assess probability) of such events in the near (1 to 5 year) and mid (5 to 10 year) timeframe.

Black & Veatch’s approach to meeting the requirements of the three deliverables was designed to collect, process and systematically analyze the data required to estimate the risk of gas supply curtailment to the electric generators within ERCOT’s service region and is illustrated in Figure 1.

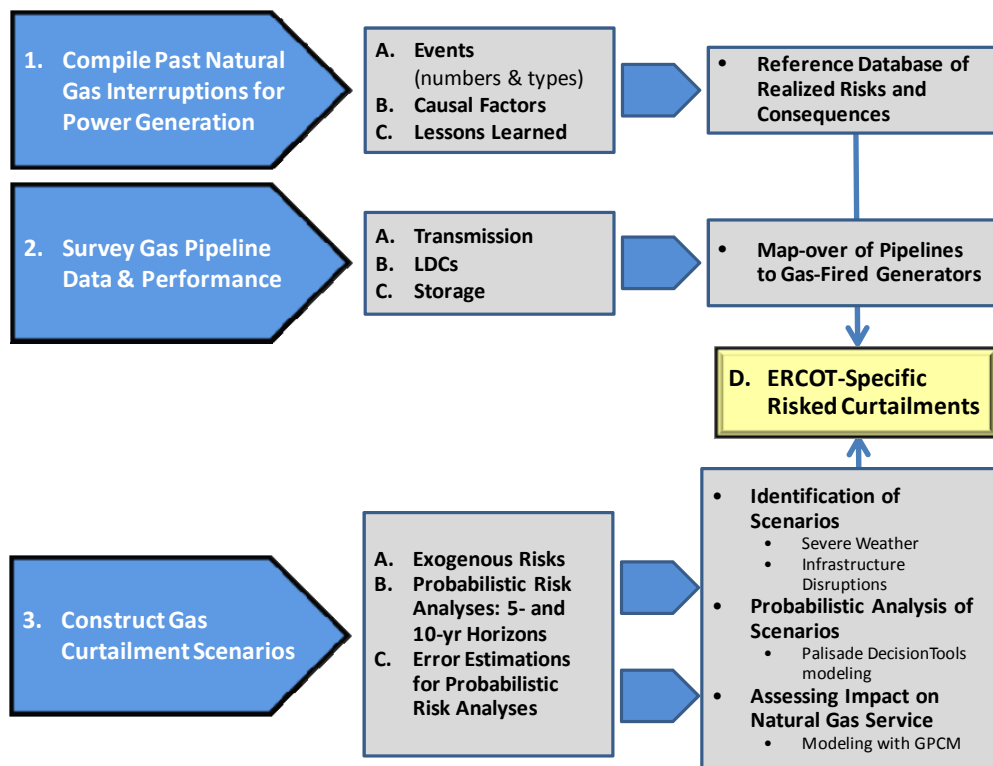


Figure 1 Black & Veatch Approach to Delivery of Phase-1 Study

2.1 ORGANIZATION OF THIS REPORT

The remainder of this report is organized as follows:

Section 3: Review of Historical Curtailment – Summary of our review of the historically reported incidents of natural gas curtailments within ERCOT.

Section 4: Natural Gas Infrastructure – Summary of the natural gas infrastructure serving electric generators within ERCOT’s service region.

Section 5: Risk Assessment – Approach & Assumptions – Overview of overall approach and analytical tools and a list of key assumptions underlying Black & Veatch’s analysis.

Section 6: Risk Assessment – Results – Discussion on analytical approach, scenarios examined and the results of risk assessment

Finally, we include Appendices that provide more detailed descriptions, information and results from the study.

3.0 Review of Historical Curtailments

An understanding of ERCOT’s historical experience with natural gas curtailments is an important first step while examining the risk of any potential future disruptions to natural gas supply to electric generators within ERCOT’s service region. We undertook a review of available historical data on natural gas curtailment incidents in order to collate and examine the experience to date with natural gas curtailment to electric generators.

It should be noted that the term “curtailment” has different definitions depending on the industry and the agency that utilizes it. The Federal Energy Regulatory Commission (FERC), National Energy Technology Laboratory (NETL) and the Railroad Commission of Texas (TRRC) each has a different definition and understanding of the term curtailment as it is applied within their jurisdictions. For the purpose of this study, the working definition for curtailment that is *“Loss of normally expected gas delivery as a consequence of supply or transportation interruptions caused by weather-driven, contractual or operational issues”*.

Black & Veatch conducted research, using publicly-available information sources, to gather facts about historical cases of natural gas delivery interruptions within Texas that have impacted gas-fired electric power generation. It should be noted that gas supply interruptions also can occur due to contractual provisions, TRRC defined regulations requiring disruptions of gas supply to power generators, as well as non-delivery of contracted supply⁵.

Black & Veatch also worked with ERCOT to locate event data that is relevant to natural gas supply reliability. Historical ERCOT Monthly Operations Reports⁶, NERC System Disturbance Reports⁷, various FERC issued reports and historical pipeline operational information were sources of timeline information. In addition, ERCOT issued a survey questionnaire prepared by Black & Veatch to the natural gas-fired electric generators within its service region seeking information on natural gas curtailments experienced by the generators during their operational history. The information gathered from these various sources were reviewed to compile chronological timelines for events involving curtailments or other disturbances of natural gas supplies to generation facilities. Although the focus of the study was on the ERCOT region, gas-related incidents elsewhere were reviewed to the extent that they offer insights into issues relevant to ERCOT.

For each occurrence of natural gas interruption that was identified, Black & Veatch examined the causal factors leading to the gas interruption. It should be noted that gaps in data availability and historical record-keeping placed constraints on examining and accurately determining the cause of every incident of curtailment that was reviewed. Causal factors that were investigated include:

- Severe cold weather conditions in ERCOT
- Severe cold weather conditions in regions of competing gas demand

⁵ TRRC Gas Curtailment Plan of 1973. Oil and Gas Docket, Gas Utilities Division, No. 20-62, 505, Docket No. 489, January 5, 1973. <http://www.rrc.state.tx.us/meetings/dockets/docket489.php>

⁶ ERCOT Operations Monthly Reports. <http://www.ercot.com/mktinfo/reports/omr/>

⁷ NERC System Disturbance Reports. <http://www.nerc.com/page.php?cid=5166>

- Operational interruptions caused by pipeline outages
- Tropical cyclones (hurricanes, tropical storms and tropical depressions)
- Other

Black & Veatch examined the common threads linking the instances of natural gas interruption identified and their causes to identify lessons that can be learned by ERCOT from these historic experiences.

3.1 DATA AVAILABILITY & SOURCES

Historical records of natural gas curtailment to electric generators were found during our review to be limited. Our review found that most of the data available was for the last decade rather than for previous time periods, reflecting better record keeping in more recent years. The primary data sources that were examined as potential sources of records of historical natural gas curtailment are summarized in Table 1.

Table 1 Sources of curtailment information.

SOURCE NAME	AVAILABLE STARTING DATE	AVAILABLE ENDING DATE	NOTE
ERCOT Gas Curtailment Survey	9/13/1994 (Earliest Curtailment Reported)	4/1/2011(Latest Curtailment Reported)	Responses to survey sent to natural gas fired electric generators within ERCOT's service region as part of this study
ERCOT Operator Logs	Dec 2002	Aug 2011	Operator Logs provided by ERCOT filtered using the key words "Gas Curtailment" and Gas Restriction"
ERCOT Monthly Operations Reports	Jan 2004	Jul 2007	Focused on Operating Condition Notice
National Energy Technology Laboratory (NETL) Electric Disturbance Events (OE-417) Annual Summaries	Year 2000	Year 2011	Focused on the Major Electric Disturbances and Unusual Occurrences
Railroad Commission of Texas (TRRC) Pipeline Incident Reports and separate response to ERCOT Data Request	12/12/1983	2/2/2011	TRRC response to data request sent as part of this study

Secondary sources of data that were examined and utilized are listed in Appendix A – Data Sources.

There was limited overlap between curtailment or disruption data available through natural gas-focused and power-focused entities. NETL and other sources of curtailment data from power-focused entities placed limited or no emphasis on capturing or reporting the natural gas fuel aspect of recorded events and, at best, natural gas curtailment could only be inferred for some of those incidents. Pipeline electronic bulletin boards and other natural gas-focused sources, in turn, did not capture impacts of gas curtailment events on electric generators in detail although such impacts were inferred by Black & Veatch where possible. ERCOT’s operator logs were most directly applicable of the various primary data sources reviewed. Documented gas curtailments outside of contractual agreements were relatively rare among the incidents reviewed with most curtailment incidents reviewed appearing to be contractually permitted.

3.2 SUMMARY OF HISTORICAL CURTAILMENTS & CAUSES

In all, 216 incident records were identified upon review of the various data sources that were examined. The majority of historical curtailment incidents reported for ERCOT were winter occurrences associated with freezing weather as shown in Figure 2. A key finding of those incidents is that the majority of historical curtailments to electric generators within ERCOT’s service region during freezing weather appear to have been contractually permitted and triggered by a temperature threshold. A small number of cold-weather-related incidents were

attributed to physical disruption of upstream supply or infrastructure. A FERC-NERC report⁸, for example, attributed a majority of the February 2011 generation loss to problems with winterization related to plant operations and with a smaller portion attributed to gas supply loss from wellhead freeze-offs and field-level infrastructure

failures. Figure 3 shows a fishbone diagram⁹ outlining possible causes and effects leading to gas system failure related to freezing weather. In a failure modes and effects analysis

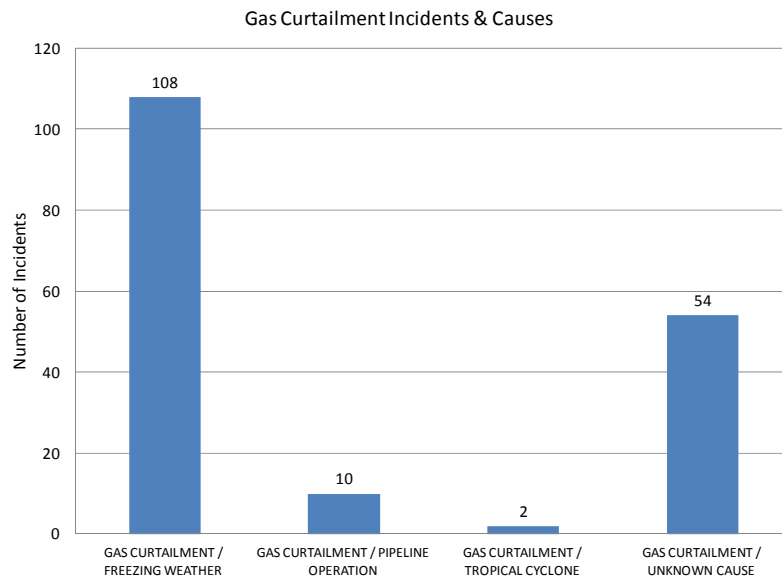


Figure 2 Numbers of documented gas-curtailment incidents studied.

⁸ Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011, Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC), August 2011, 357 p.

⁹ A fishbone diagram (also known as an Ishikawa diagram) is a tool used to identify failure pathways in a failure mode and effects analysis (FMEA). In the current study, fishbone diagrams are used to summarize

(FMEA), these are possible cause-and-effect strings that can affect gas-system performance, based on general historical experience. The precise cause-and-effect string is not always expressly published for every curtailment event. The potential factors leading to gas supply disruptions due to freezing weather are 1) freezing of onshore gas wellheads, 2) onshore power grids trip and pipelines lose pressure as gas compressors and/or Supervisory Control and Data Acquisition (SCADA) systems lose power and 3) contractual provisions with gas suppliers/transporters that allow curtailment of gas supply to power generators based on temperature thresholds.

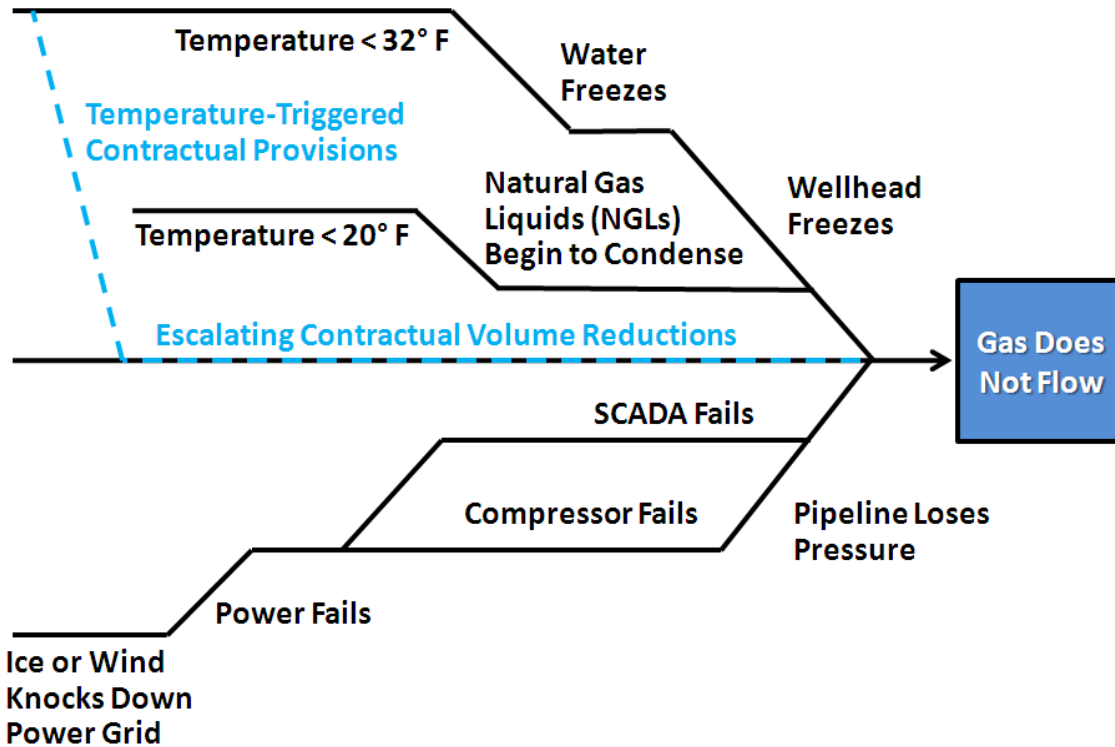


Figure 3 Fishbone diagram for possible freezing-weather causes of gas curtailments.

Pipeline operations represented the next largest driver of natural gas curtailment incidents historically. Those incidents were caused by unscheduled maintenance and line ruptures. There were 10 reported incidents of gas curtailments related to pipeline disruptions in the data reviewed. In addition, 54 incidents of gas curtailment were reported without any specified cause although our further research showed that none were linked either to freezing temperatures in winter or tropical cyclone occurrences in summer. Since those

how causative agents might lead to gas curtailments but without identifying likelihood of the alternative pathways.

incidents were not weather-related, they were assumed to be infrastructure-related and grouped together with pipeline disruptions. Figure 4 shows a fish bone diagram examining the cause and effect leading to gas system failure related to pipeline disruptions.

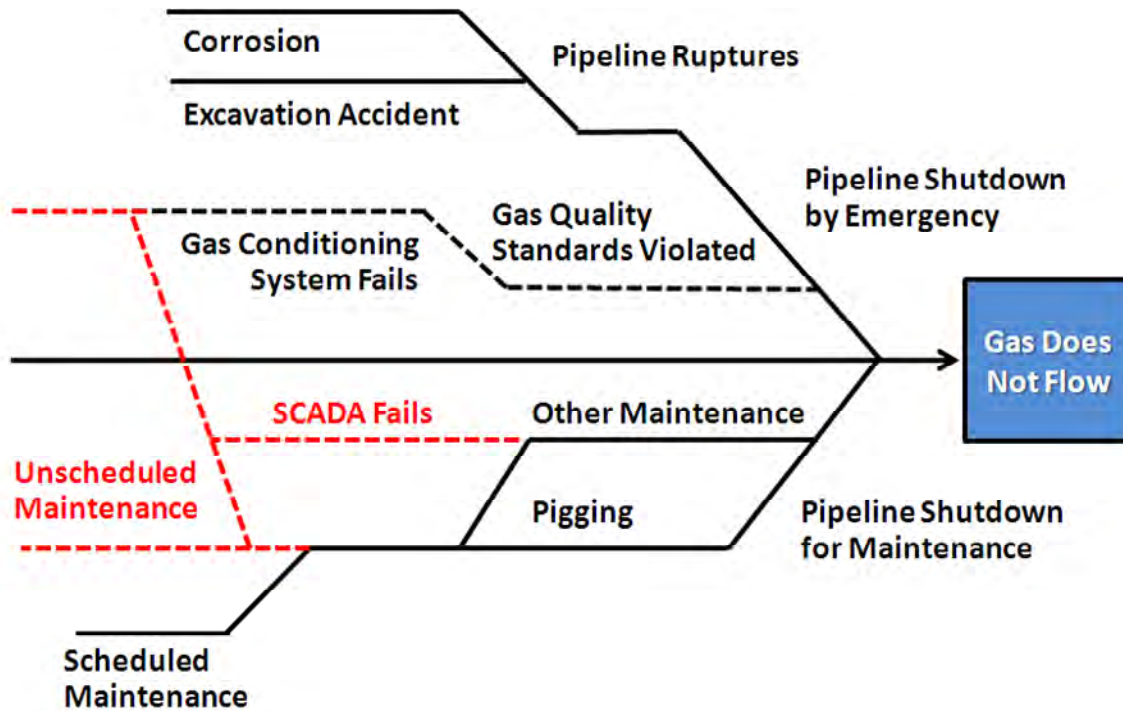


Figure 4 Fishbone diagram for possible pipeline-related causes of gas curtailments.

Only 2 incidents of gas curtailments driven by tropical cyclones were observed in the reviewed data¹⁰. Figure 5 shows a fishbone diagram examining the possible causes and effects leading to gas system failure related to tropical cyclones. The three main failure paths driven by tropical cyclones are 1) shutting of offshore platforms due to a storm in the Gulf of Mexico (GOM); 2) onshore flooding caused by excessive rainfall that impacts gas processing facilities; and 3) high winds associated with tropical storms knock down power lines and cut-off power to gas pipeline compressors and/or SCADA systems.

¹⁰ Weather-related incidents in the ERCOT Operator Logs dated from 2002 and later. Major tropical cyclone landfalls and coastal flooding events occurred in 1989 and 2001 prior to first records in the ERCOT Operator Logs.

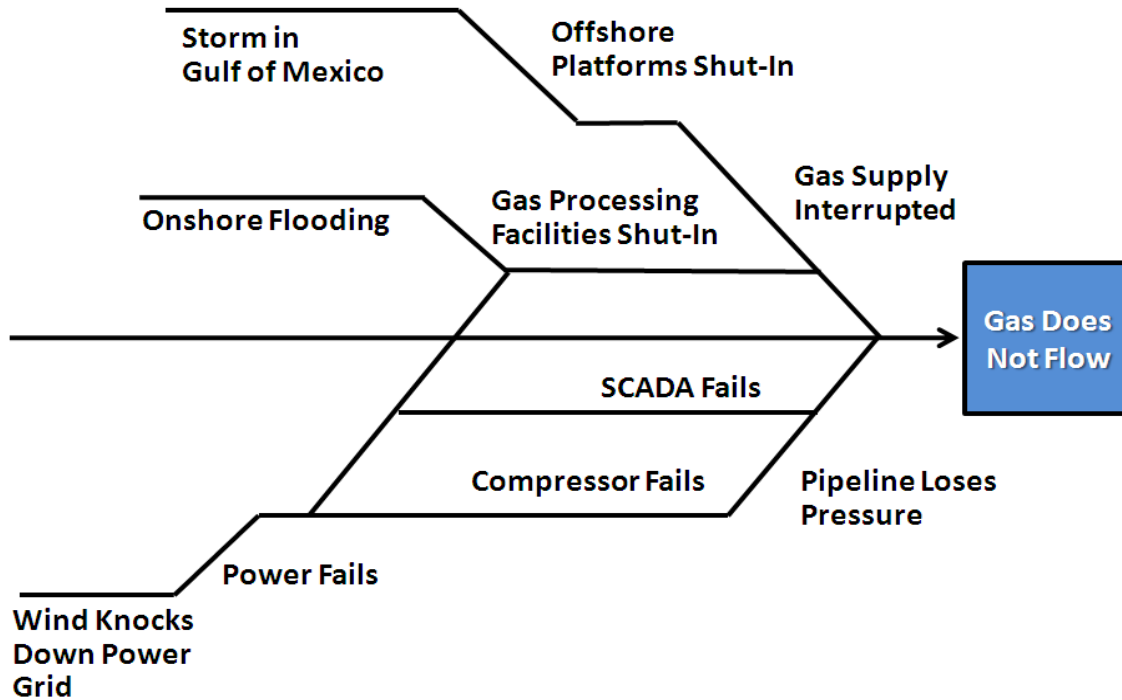


Figure 5 Fishbone diagram for possible tropical-cyclone-related causes of gas curtailments.

3.3 BEST PRACTICES & LESSONS TO BE LEARNED

A relatively small number of curtailment incidents outside of contractual agreements were observed overall in the data reviewed as part of this study. This would indicate that natural gas supply has proven to be a reliable fuel source for power generators operating in ERCOT and that market liquidity and commercial agreements appear to largely be effective in procuring natural gas supply for electric generators. The growth of onshore unconventional natural gas resources in Texas may be expected to help make natural gas supply even more readily available for ERCOT generators.

Survey responses indicate that some electric generators in the Dallas-Fort Worth region have entered into contractual agreements that allow curtailment of their natural gas supply in the event of extreme cold weather which is driven in part by curtailment priorities defined by the TRRC. Appendix D of the report includes the Curtailment Plan requirements of the TRRC in more detail. In addition to regulatory requirements, contractual agreements also can reflect a trade-off between the cost of firm supply and the costs for contractual interruption based on historical experience that natural gas supply is available when needed during most days of operation.

Switching to oil was observed in historical data as a mitigation measure when gas curtailments were in effect due to contractual terms. It should be noted that the economics of switching may place restrictions on the ability to switch to oil going forward.

Connectivity to multiple pipelines or to storage facilities would provide both supply flexibility to minimize delivered gas supply costs and fuel-supply redundancy for generators when curtailed by one pipeline.

Increased coordination between natural gas and power industry regulating agencies could help ensure cross-capture of information as the role of natural gas as a fuel source for power generation continues to grow. If ERCOT is expected to monitor fuel impacts on the reliability of the electric grid, better data capture of curtailment incidents is needed. This study recommends the following measures to better capture information related to natural gas supply and curtailments to electric generators:

- Training of ERCOT operators to improve their familiarity with the natural gas infrastructure will help to increase the data accuracy of operator logs. As identified in this study, the operator logs comprised the most complete data source recording the disruption of natural gas supply to electric generators within the ERCOT service region.
- Adding standardized questions on gas delivery-related issues into annual reports submitted by the electric generators will allow ERCOT to track and assess any trends associated with natural gas supply disruptions that electric generators experience. It will also help ERCOT to understand and manage gas supply-related risks.
- Continued and growing coordination between ERCOT and the TRRC in development of reports for capturing and sharing information on gas supply delivery issues impacting electric generators. Coordinated actions can foster better data capture for both organizations.
- Review of gas-supply agreements and gas-curtailment policies could help determine whether new policies or regulations are required to increase the reliability of ERCOT generation. In addition to cost considerations, contractual agreements that require curtailment of gas supply to generators or mandatory curtailment policies as defined by the TRRC may inhibit a power generator's ability and motivation to acquire firm gas supply.

4.0 Natural Gas Infrastructure & Market

Texas is the largest producer as well as consumer of natural gas in the U.S., contributing about one-third of the total production in the U.S. and consuming one-seventh (with over 85% of it being consumed in the industrial and electricity generation sectors)¹¹. As a consequence, Texas enjoys one of the most robust natural gas markets in North America with well-developed infrastructure that includes natural gas production facilities, natural gas processing facilities, interstate and intrastate natural gas pipelines and natural gas storage facilities.

Texas leads all states in the U.S. in the number of pipeline miles with more than 21,000 miles of interstate natural gas transmission pipelines and more than 130,000 miles of intrastate natural gas transmission and distribution pipelines making it one of the best connected and served markets in the U.S.¹²

4.1 INTERSTATE PIPELINES

Among the major interstate pipelines serving electric generators within ERCOT's service region are Texas Eastern Transmission, CenterPoint Energy, El Paso Natural Gas, Natural Gas Pipeline Company of America, Tennessee Gas Pipeline, and Transcontinental Pipeline (Figure 6). Most of these interstate pipelines transport production from the Gulf Coast region and flow north to serve the Midwest market and northeast to serve the East Coast markets of the U.S. El Paso Natural Gas moves gas produced in West Texas fields to serve the West Coast.

Since those pipelines move gas that is produced in and near Texas to consumers in the Midwest, East Coast and West Coast, the other market destinations can be considered as representing competition for natural gas supply for electric generators within ERCOT's service region. The potential for gas supply disruption to electric generators within ERCOT's service region that is posed from competing demand served by these pipelines is one of the risk factors considered in this study and is discussed in detail in Section 5 and Section 6.

¹¹ Natural Gas Annual Supply & Disposition by State, US Energy Information Administration. http://www.eia.gov/dnav/ng/ng_sum_snd_dcu_nus_a.htm

¹² Texas Pipeline System Mileage, updated October 28, 2010., Railroad Commission of Texas. <http://www.rrc.state.tx.us/data/gasservices/vitalstats/mileage.php>

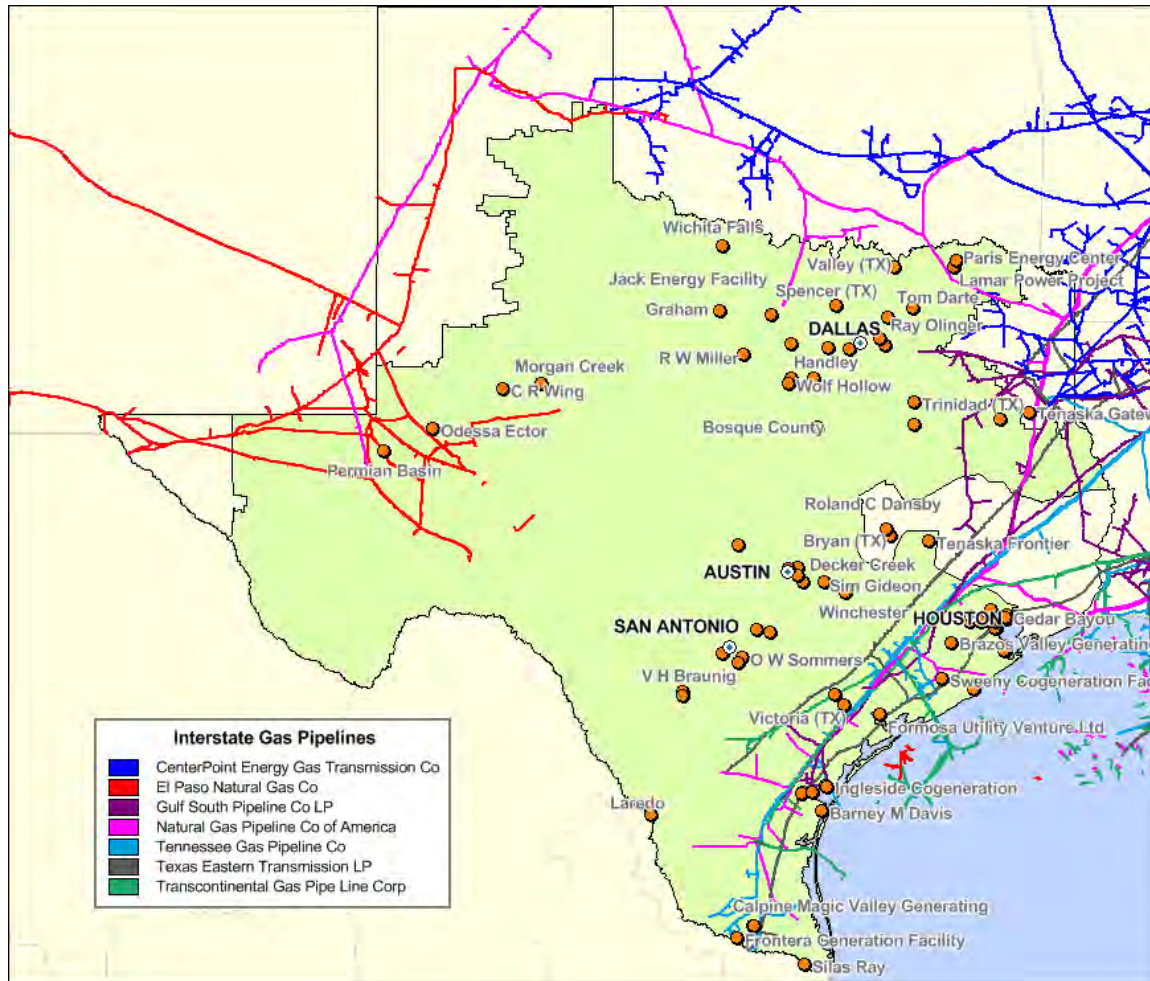


Figure 6 Interstate Natural Gas Pipelines Serving ERCOT Generators

4.2 INTRASTATE PIPELINES

Texas holds the distinction of having the largest number as well as the most miles of intrastate pipelines in the U.S. Those pipelines gather and transport natural gas from supply basins in Texas to local gas distribution companies, electric generation and industrial and municipal consumers, as well as to connections with intrastate pipelines and interstate pipelines that transport this gas to end-use markets in the Midwest, East Coast and West Coast. The major players in the intrastate pipeline market include Atmos Energy Corporation, Enterprise Products Partners, L.P., Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. owning and operating multiple, large Texas intrastate pipelines between them (Figure 7). Texas intrastate pipelines are regulated by the TRRC and are subject to alternative regulations compared with those of FERC-regulated interstate pipelines. The TRRC’s oversight over intrastate pipelines is largely focused on safety and pipeline integrity with less oversight, when compared to FERC-regulated pipelines, related to commercial issues. This can result in less transparency about the available capacity and the transportation costs associated with intrastate pipelines when compared to interstate pipelines. It should be noted, however, that the intrastate pipeline

market in Texas is highly competitive when multiple pipeline or supply alternatives are available to an end-user.

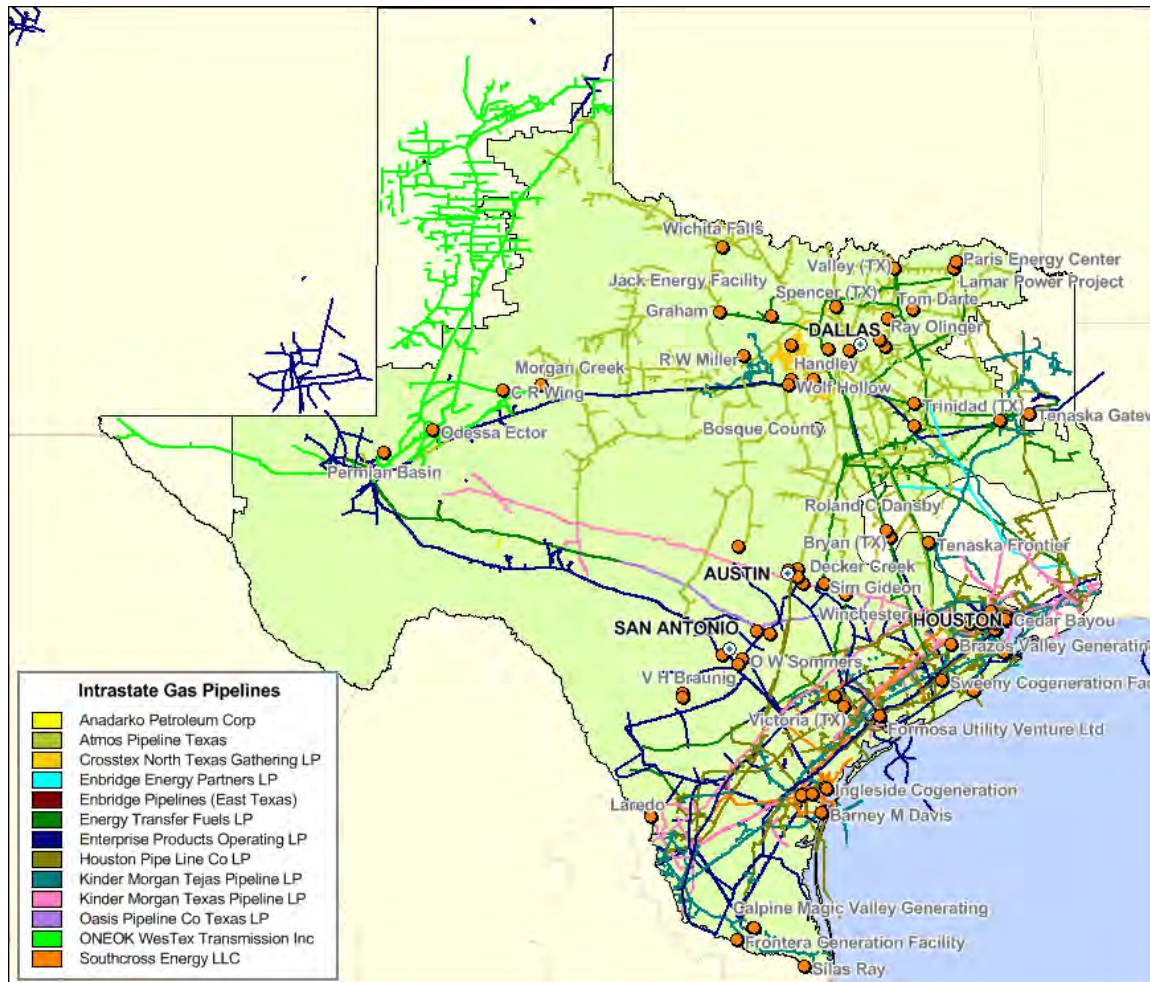


Figure 7 Intrastate Natural Gas Pipelines Serving ERCOT Generators

4.3 NATURAL GAS STORAGE FACILITIES

Natural gas is commonly stored in underground rock formations such as depleted oil and gas reservoirs or leached caverns in salt domes. Natural gas storage helps to match the relatively constant production profile of natural gas with its highly seasonal consumption pattern by creating flexibility in the market and allowing participants to store large volumes of natural gas in summer when the traditional heating load is typically low and to use this stored gas in winter when the heating load increases. Texas stands fourth in the U.S. in total underground natural gas storage capacity with over 783 Bcf of storage capacity¹³. Figure 8 shows the underground natural gas storage assets within ERCOT’s service region.

¹³ Underground Natural Gas Storage Capacity, as of December 2010, updated December 29, 2011, US Energy Information Administration.

http://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SAC_Mmcf_a.htm

In addition to helping balance the seasonal demand with relatively constant production, natural gas storage also offers short-term flexibility to the natural gas market by being a source of supply when demand is higher than anticipated and being able to absorb supply when demand is lower than anticipated. It is this attribute of natural gas storage that makes it attractive to electric generators seeking to manage the day-to-day volatility in their gas supply needs. Natural gas storage offers electric generators the ability to quickly access supply when their generation needs ramp up or an alternate destination for surplus natural gas supply when generation needs ramp down. High deliverability storage or storage with the ability to inject or withdraw high volumes of gas each day relative to the total storage capacity of the field offers the most flexibility to swing with the daily gas supply needs of electric generators.

Storage assets in Texas include both regulated assets that are part of natural gas pipeline systems as well as stand-alone storage assets managed by independent operators.



Figure 8 Natural Gas Storage Assets in ERCOT’s Service Region

4.4 ROLE OF GAS COMPRESSORS

Gas production fields, storage fields and both intrastate and interstate pipelines depend upon gas-compression technologies to sustain their operations. A significant loss of

compression can interrupt pipeline flows and threaten curtailment of gas deliveries to customers.

Gas compressors are built on either reciprocating or centrifugal technologies and with either combustion-powered or electric-powered-drive driver technologies. Combustion-driven compression historically has used gas provided by a pipeline and thereby has offered a significant level of self-sufficiency for pipeline operations. In contrast, electric-drive compressors depend upon electrical power which is purchased from an outside source (not controlled by the pipeline) which represents a risk factor beyond the control of the pipeline. Based upon Black & Veatch research, Table 3 summarizes the proportions of gas- and electric-drive compressors installed in Texas. Although the numbers in Table 3 are not represented as a comprehensive inventory, the most significant message is that about 18% of all transmission pipeline compressors are electric-drive and therefore at risk to power outages. However, pipeline operations often are designed to be able to continue with limited compressor outages whether gas fired or electric-drive.

Table 2 Indicative numbers of natural gas compressors serving the Texas gas pipeline infrastructure.

COMPRESSOR TYPE	GAS FIELD	TRANSMISSION PIPELINE	UNDERGROUND STORAGE	TOTAL
Gas Combustion	4	498	34	536
Electric	1	111	2	114
Total	5	609	36	650

Since the 1990s, the general trend among gas pipelines has been toward selection of electric-drive compressors based on benefits of lower maintenance costs, lower noise emissions and lower air emissions¹⁴. Any corresponding increase in risks of power outages generally has been considered an acceptable trade-off.

4.5 SURVEY RESULTS OF NATURAL GAS INFRASTRUCTURE SERVING ERCOT GENERATORS

As part of this study, Black & Veatch conducted a survey, through ERCOT, of the natural gas-fired electric generators within ERCOT’s service region to assess the natural gas infrastructure serving their facilities. The survey requested information on the pipelines, local distribution companies (LDCs) and storage facilities serving each electric generator. The information provided through survey responses was supplemented by a number of data sources to create a compilation of the natural gas infrastructure serving electric generators within ERCOT’s service region. The data sources utilized include FERC, TRRC, pipeline electronic bulletin boards (EBBs), the US Energy Information Administration (EIA), Black & Veatch’s proprietary database underlying our large body of work in natural gas market analysis and third-party vendor data. While the individual survey results are confidential, we share the following observations summarizing the survey responses:

¹⁴ *Factors That Influence the Selection of Electric Motor Drives For Natural Gas Compressors*, Prepared for The INGAA Foundation, Inc. by Southwest Research Institute, SwRIPProject 18-2090, April 1999, 58 p.

- The survey on natural gas infrastructure was sent to 109 gas-fired electric generators within ERCOT’s service region and 82% of electric generators fully or partially responded to the survey. The survey results summarized below are applicable to this population of respondents alone.
- There is diversity in the natural gas infrastructure serving the electric generators surveyed with multiple pipelines serving these generators, namely, 44 different natural gas pipeline systems delivering power-generation fuel within ERCOT’s service region. Of these 44 pipelines, 7 are interstate natural gas pipelines and 37 are intrastate natural gas pipelines. Figure 9 shows the top 10 pipelines serving the electric generators in ERCOT’s service region.
- Approximately 60% of the generators that responded to the survey (corresponding to 51,550 MW of nameplate capacity¹⁵) have access to more than one natural gas pipeline interconnect which can create redundancy in natural gas supply alternatives (Figure 10).

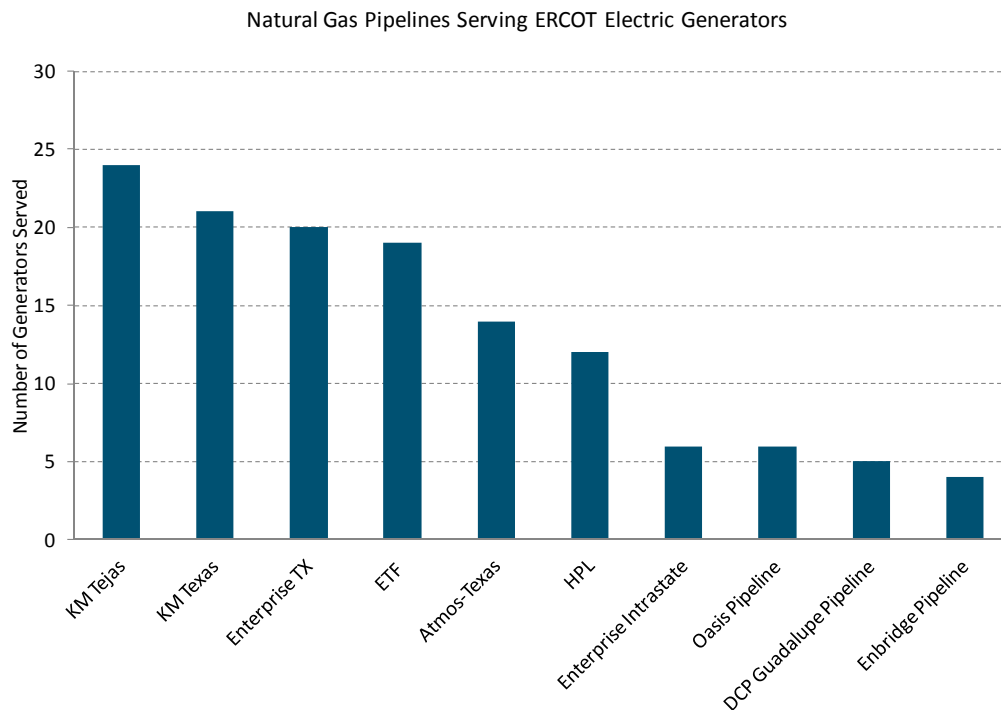


Figure 9 Natural Gas Pipelines Serving ERCOT Electric Generators

¹⁵ The nameplate capacity is inclusive of generation capacity that is part of Private Use Networks which generally serve their own industrial loads rather than selling power into ERCOT.

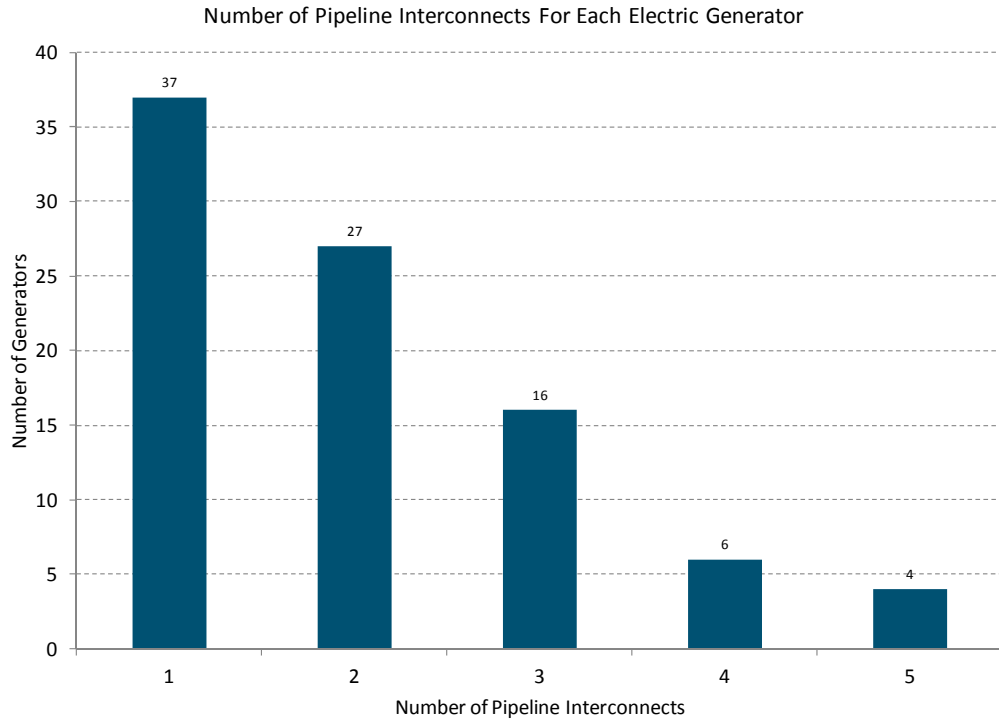


Figure 10 Number of Pipeline Interconnects for Each Electric Generator

- All the generators that provided information on their capacity and peak needs noted that they had adequate pipeline capacity to meet their peak demand. Over 65% of these generators (corresponding to over 39,400 MW of nameplate capacity¹⁶) indicated that they had access to capacity in excess of 150% of their peak needs. Figure 11 shows the level of redundancy in pipeline capacity that was reported by the survey respondents. As seen in this histogram, many electric generators have access to substantial excess pipeline capacity that can be expected to increase their reliability of supply and offset the impacts of any supply or pipeline disruptions.
- Access to, or contracts for, gas storage appears to be limited, although storage is used on a daily basis by gas suppliers and interstate and intrastate pipelines to manage flows on their systems. Only 23% of the respondents reported information on natural gas storage as part of their supply portfolio.

¹⁶ The nameplate capacity is inclusive of generation capacity that is part of Private Use Networks which generally serve their own industrial loads rather than selling power into ERCOT.

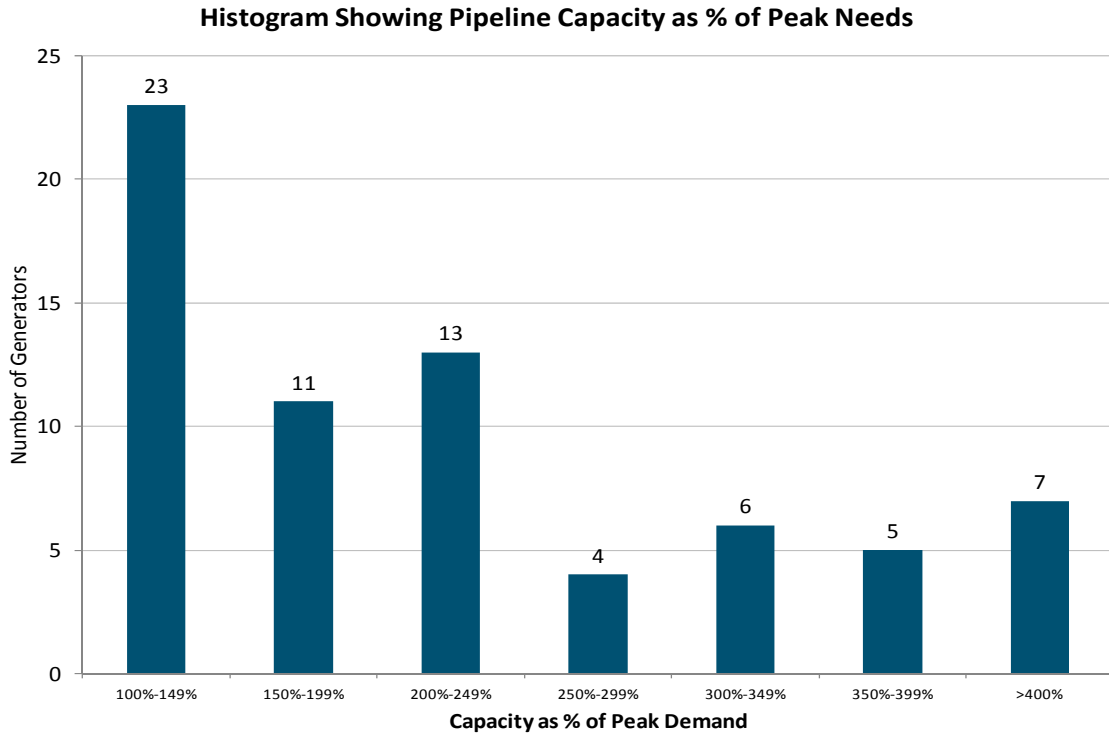


Figure 11 Pipeline Capacity as Percentage of Peak Needs

Overall, based on the responses by generators to the survey, it appears that ERCOT’s electric generators create reliability and redundancy of gas supply capability through their interconnections with multiple pipelines and access to a level of capacity that is well in excess of their peak natural gas needs.

5.0 Risk Assessment - Approach & Assumptions

5.1 SUMMARY OF APPROACH

Black & Veatch approached the risk assessment as a combined economic and quantitative analysis with the final objective being development of risk-based likelihoods of natural gas curtailments that could affect gas-fired generation for scenarios that are specific to ERCOT.

Our work effort for Deliverable 3 was focused on three main analytical efforts:

- A. Identification of Scenarios
- B. Probabilistic Analysis of Scenarios
- C. Fundamental Analysis of Scenarios

A. Identification of Scenarios

This study utilized a scenario-based approach to assess the risk of gas supply curtailment to electric generators within ERCOT's service region. Black & Veatch's review of historical curtailment events provided the basis for selecting and shortlisting potential risk scenarios for ERCOT to be analyzed in this study. As discussed in Section 3, freezing weather was found to be the most significant risk factor driving natural gas supply curtailment to electric generators within ERCOT's service region. Over 60% of the recorded incidents of gas supply curtailments to electric generators that were reviewed were driven by a freezing weather occurrence, including some driven by contractual provisions which stipulated temperature milestones in their curtailment schedules. Other risk factors that were found during our review of historical curtailments were pipeline disruptions and tropical cyclones. Accordingly, the scenarios shortlisted for the study are primarily weather-driven or infrastructure-driven and listed below:

1. Freezing weather in Texas and outside Texas
2. Pipeline disruptions
3. Tropical cyclones

For each given scenario, the study examined a family of occurrences of increasing severity to facilitate understanding of the shape of the risk profile associated with a given risk factor as opposed to a point estimate of the risk.

Notable historical curtailments where available were utilized as benchmarks within the scenarios analyzed.

B. Probabilistic Analysis of Scenarios

The next analytical step was the probabilistic analysis of each of the scenarios to determine the risk associated with their occurrence. Those analyses adopted an empirical approach which distinguished frequencies of potential causal events from frequencies of documented curtailment events¹⁷. Most notably, frequencies of occurrence of problematical weather can

¹⁷ A causal event is an environmental or operational factor which, based on historical experience, could cause a gas curtailment event. For events associated with weather, it is possible to derive causal-event statistics which are independent of curtailment-event data.

be calculated for years where records for curtailment events do not exist. But the information of greatest interest remains in the curtailment-event reports. Accordingly, the approach adopted in this study emphasized analysis of curtailment-event data directly wherever possible.

The probabilistic (stochastic) methodology employed the following sequence of actions:

- Compile curtailment event data for each scenario as defined by a causal relationship (for example, freezing temperature, tropical cyclone, pipeline failure)
- For each scenario, differentiate the curtailment event data into sub-populations if possible (for example, curtailments associated with freezing temperatures or high heating-degree day numbers either in Texas or elsewhere)
- For each population (or sub-population) of curtailment events in each scenario, employ statistical-analysis software to derive a best-fit probability distribution function (*PDF*) that describes frequency of event occurrence
- To the extent that documented reports allowed, derive *PDFs* that describe frequency of lost generation by size (MW) in each scenario (This was possible for freezing-weather and pipeline-outage scenarios.)
- As necessary, map-over causal-event *PDFs* onto selected curtailment thresholds expressed in units of generation (MW). (This was necessary for tropical cyclones.)
- Employ the *PDFs, along with scaling factors for growth or decline of gas dependencies*, to derive probabilities of occurrence of the subject hazard (curtailment event) at selected timeline thresholds (for example, 5- and 10-year).

The robustness of probabilistic results for causal events was strongest for weather data which comprised large, continuous data sets. Probabilistic results for curtailment event data carried much larger uncertainties associated with the much smaller and less continuous nature of their data. For daily weather data compiled for winter months (December, January, February) over the period of January 1981 through February 2011, the data set available for each station typically comprised 2,766 measurements. In contrast, curtailment event data were typically limited to fewer than 100 incident reports (Table 3). After incidents were analyzed to define discrete events, and especially as sub-categories were sought among the types of events, the data available to define a sub-scenario were reduced to 25 or fewer examples in many cases. For comparison, science and engineering analyses commonly find that the minimum number of samples required for application of distribution-function statistics falls in the range of 15-50¹⁸ which, in the current study, is matched by the freezing-weather and pipeline-outage incident reports but not by the tropical-cyclone incident reports (Table 3). Accordingly, analyses for freezing-weather and pipeline-outage events proceeded directly using loss reports (typically MW rather than Bcf/d, based on relative numbers of available reports) but for tropical-cyclone incidents it

¹⁸ The minimum sample size depends on the distribution function chosen but the minimum number generally increases as the function differs from a Normal (Gaussian) distribution. See, for example, Meyer S. L. (1975) *Data Analysis for Scientists and Engineers*, John Wiley & Sons, Inc., New York, 413 p..

was necessary to model indirectly using frequency of occurrence of tropical-cyclone activity and implied impacts on gas supplies which then were translated to equivalent MW losses in ERCOT. The effects of different sample sizes on goodness-of-fit and on uncertainties (error bars) for risk levels is illustrated in Appendix B - Weather Analysis.

Table 3. Sizes of curtailment-incident data sets available for definition of events and probabilistic risk analyses.

PERIOD OF RECORD	FREEZING WEATHER (1)			TROPICAL CYCLONE (2)			PIPELINE (3)		
	Total	Incl. MW Loss Reports	Incl. Bcf/d Loss Reports	Total	Incl. MW Loss Reports	Incl. Dth/d Loss Reports	Total	Incl. MW Loss Reports	Incl. Dth/d Loss Reports
2011-2002	106	62	7	2	1	1			
2011-1987							64	46	0

(1) Excludes two other events (Dec 1983, Dec 1989) for which MW and Dth/d loss data were not available. Includes incidents caused by contractual provisions.
 (2) Excludes two other landfall and flooding events (1989, 2001) for which ERCOT records do not exist.
 (3) Includes combination of events documented as “pipeline” plus other events documented as “unknown” but where a pipeline involvement was inferred.

C. Fundamental Analysis

For each scenario identified, Black & Veatch used a fundamental supply-demand model to examine the sufficiency of the natural gas infrastructure and natural gas supply to impact on natural gas service to electric generators in the ERCOT region. This analytical approach incorporates a network representation of the physical capabilities of the natural gas infrastructure in serving electric generators rather than the contractual obligations on the natural gas facilities. Although there may be financial implications to procuring the gas supply needed, natural gas service is available to electric generators subject to the regulatory and physical constraints of the system. In addition, procuring all the bi-lateral contracts required to comprehensively capture the contractual obligations within ERCOT is a significant, if not impossible, undertaking that is complicated by the lack of publicly available information.

Black & Veatch estimated the natural gas demand or supply implications associated with each of the scenarios and used these modified demand and supply assumptions as inputs to the fundamental market model. The analysis examined any resulting constraints within the system (caused either through increased demand or decreased supply) that impacted the availability of natural gas supply to electric generators within the ERCOT region.

The fundamental analysis is intended to supplement the probabilistic risk analysis by defining specific forward-looking scenarios that examine the sufficiency of pipeline infrastructure and natural gas supply to meet the needs of electric generators in ERCOT’s service region.

5.2 TOOLS AND SOFTWARE

Black & Veatch utilized a combination of tools to analyze natural gas markets and infrastructure related to ERCOT's Gas Curtailment Risk Study.

Probabilistic Risk Modeling

Probabilistic risk analyses were performed using the Palisade DecisionTools Professional 5.0 software package which includes the module, " @Risk", for stochastic simulation through Monte Carlo and Latin Hypercube algorithms. For each data set analyzed, the empirical data were passed through the @Risk best-fit functions using Anderson-Darling criteria¹⁹ to identify the top candidates for describing the population as a mathematical function. Because the subject data represented physical phenomena²⁰, for which negative values were not physically possible in some attributes²¹, analyses took care as appropriate to override the default @Risk settings which allow distributions with both negative and positive numbers in the output. The @Risk settings were adjusted as necessary to avoid negative tails where they were physically impossible.

As is common with physical phenomena, the best-fit distribution functions tended to favor Log-Normal, Log-Logistic or Weibull distributions and less commonly a Normal (Gaussian) distribution. The Weibull and other log-based distributions are especially applicable to reliability analyses²². For a given data set, the best fit as indicated by Anderson-Darling criteria was adopted for further analysis although the top three distribution candidates were used to estimate uncertainties (error bars) in the adopted distribution.

Natural Gas Infrastructure Analysis

Black & Veatch utilized RBAC's GPCM™ model as a basis to analyze the ERCOT and surrounding regions' natural gas market infrastructure. The GPCM™ model operates using an algorithm to solve for optimal equilibrium price and quantities by balancing multiple demand and supply nodes in the market. As a network model, GPCM™ nodes represent production regions, pipelines, storage facilities, and end-use customer groups. Black & Veatch supports GPCM™ with a detailed database of proprietary and public sources that was modified to support the assumptions and scenarios for this study.

The GPCM™ model balances supply and demand from all the regions to find an equilibrium solution that maximizes producer profit and minimizes consumer cost. Based on Nobel Prize-winning economist Paul Samuelson's theory, the economically efficient, market-clearing solution will dispatch lower cost supplies before more expensive ones and customers willing to pay more will be served before those willing to pay less. As shown in Figure 12, quantity (Q) supplied to market grows as price (P) rises from point of production

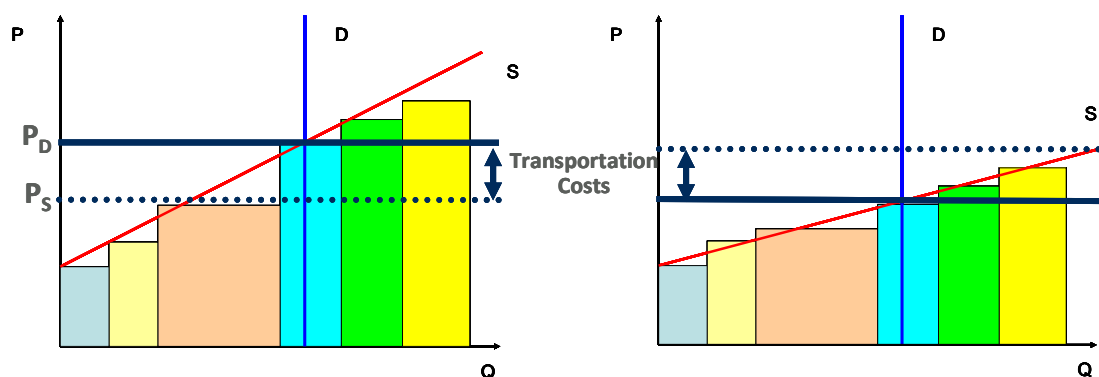
¹⁹ Anderson-Darling is one of several commonly applied tests for measuring the goodness-of-fit of distribution functions applied to real data. Compared with alternative methods, Anderson-Darling has been found to provide better performance for distributions with extensive tails.

²⁰ Physical phenomena studied here included both integer and decimal numbers. Integer representations included presence/absence of an incident or event. Decimal numbers included temperature, wind speed, heating-degree days or system impacts such as Dth/d or MW lost.

²¹ Negative values are possible for temperature but not for other attributes studied, including wind speed, HDDs, Dth/d, MW and numbers of incidents or events.

²² See Meyer S. L. (1975), op cit.

(P_s) to point of consumption (P_D) until the cost of transportation exceeds market price and supply retracts. Namely, supplies from the supply region will continue to be transported to the consumption regions until either the price differentials between the two regions drops below the transportation cost or the transportation capacity between the two regions is exhausted. The resulting prices, consumption and production quantities represent market equilibrium.



Demand Rich Region

Supply Rich Region

Figure 12 Supply-Demand Fundamentals.

One of the challenges of understanding the risk of gas curtailment to electric generators within ERCOT is to determine the demand placed on the pipelines serving these electric generators by other sources – residential, commercial, and industrial demand within ERCOT’s region as well as residential, commercial, industrial and electric demand from outside ERCOT’s region that are served by the same pipelines. By representing the entire natural gas infrastructure within North America, the GPCM™ model offers an efficient and effective methodology to model the impact of the total demand on the pipeline network from other sources within and outside of ERCOT’s region. The fundamental model represents both interstate and intrastate pipeline segments.

Black & Veatch utilized GPCM™ to assess the constraints on the natural gas infrastructure, represented as a network within the supply/demand model, in responding to demand from the electric generation sector within ERCOT under the different defined scenarios. For each scenario, a corresponding estimate of demand, supply and any applicable scenario-specific infrastructure constraints were defined.

Integrated Market Modeling

Black & Veatch has developed an Integrated Market Modeling (IMM) process which is used to prepare its integrated long-term view on energy markets, the Energy Market Perspective (EMP). In order to arrive at this market view, Black & Veatch draws on a number of commercial data sources and supplements them with our own view on several key market drivers, for example, power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and gas pipeline expansion.

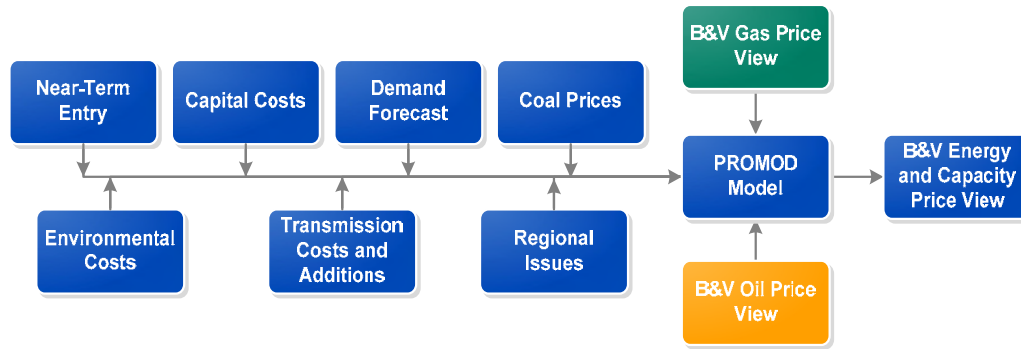


Figure 13 Black & Veatch Integrated Market Modeling Process

EMP is an integrated view of natural gas and power markets across North America, and the northern portion of Baja California, Mexico, that is electrically interconnected to the U.S.

The study period of 10 years is marked by expectations of significant growth in the use of natural gas for electric generation in North America driven by environmental policies and resulting coal retirements and the cost competitiveness of natural gas technology with other fuel sources on a fixed and variable cost basis. By providing a careful consideration of the multiplicity of factors impacting today’s energy markets, the Black & Veatch EMP uses an integrated market analysis process to arrive at a comprehensive view of how the energy world can evolve from today’s starting point, providing a sound framework for decision making. The EMP was utilized to provide underlying assumptions for this study.

5.3 GLOBAL ASSUMPTIONS

To evaluate risks of gas curtailments which could impact power generation within ERCOT, Black & Veatch made assumptions which were necessary to enable objective analyses within a reasonable scope. Assumptions which apply to all aspects of the study were as follows:

- Natural gas markets in Texas operate efficiently and economically during the analysis period and market liquidity or mandated curtailments do not comprise limiting factors contributing to risk of curtailment of gas supply to electric generators. Appendix E provides a detailed review of the liquidity of the natural gas market in ERCOT to support this assumption.
- Natural gas supply is projected to grow during the analysis period in the Lower-48 as shown in Figure 14 with growth in unconventional natural gas production led by shale gas offsetting declines in conventional natural gas production.

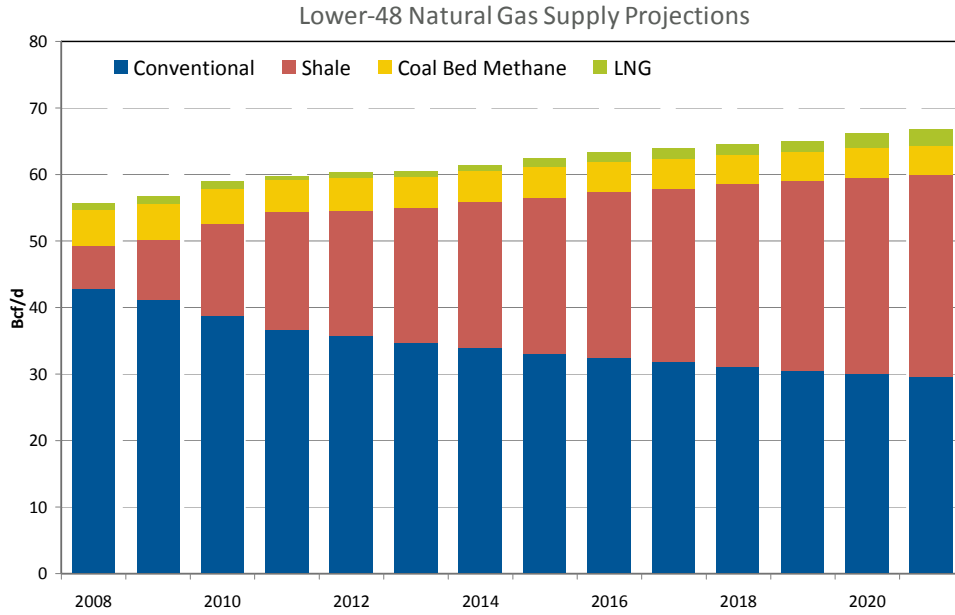


Figure 14 - Lower-48 Natural Gas Supply Projection

- Natural gas supply in Texas is projected to flatten with declines in conventional production being offset by growth in unconventional production, primarily from the Barnett Shale and Eagle Ford shale plays as shown in Figure 15.

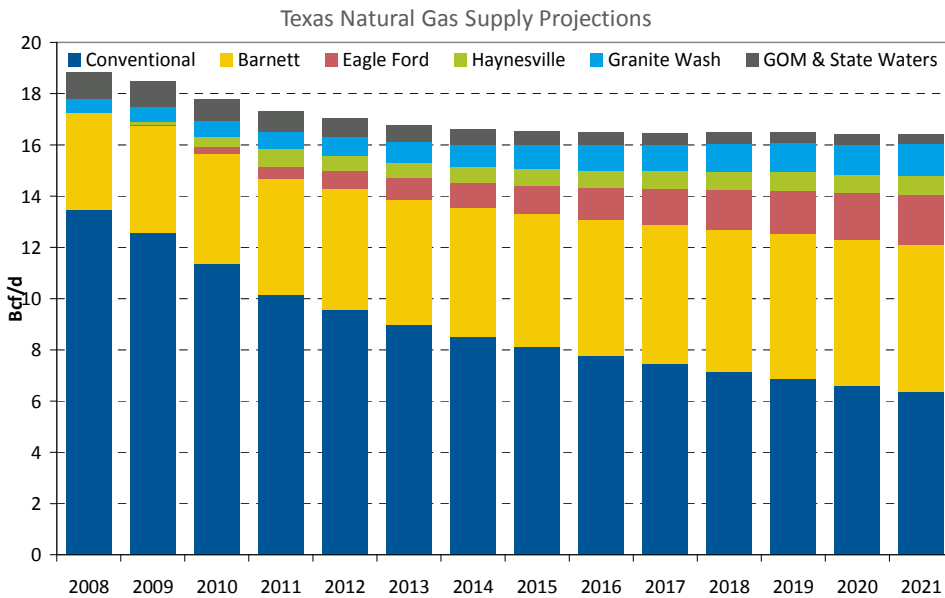


Figure 15 - Texas Natural Gas Supply Projections

- Natural gas demand in the Lower-48 is projected to grow over the analysis period as shown in Figure 16. Growth in gas demand for electric generation is the primary

driver for growth in natural gas demand as environmental regulations and lower gas prices lead to an increased share for natural gas in the electric generation mix.

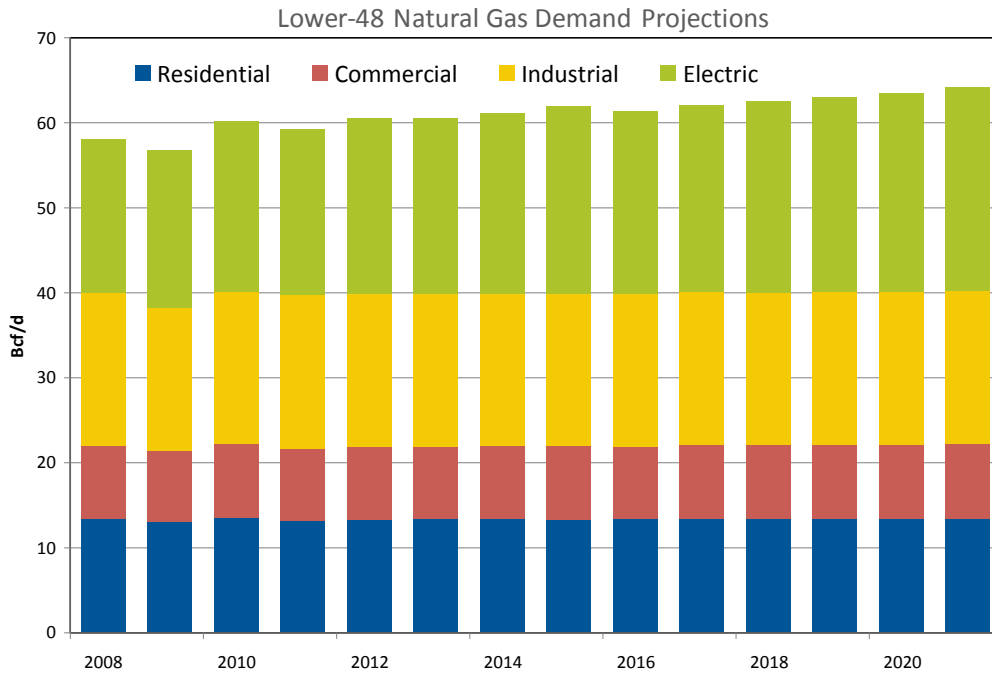


Figure 16 - Lower-48 Natural Gas Demand Projection

- Natural gas demand in Texas is projected to increase as demand for natural gas for electric generation increases as shown in Figure 17. Gas-fired generation capacity within ERCOT is projected to increase by over 15,000 MW in the next 10 years and natural gas' share of electric generation within ERCOT is projected to increase to 50% over this time period.

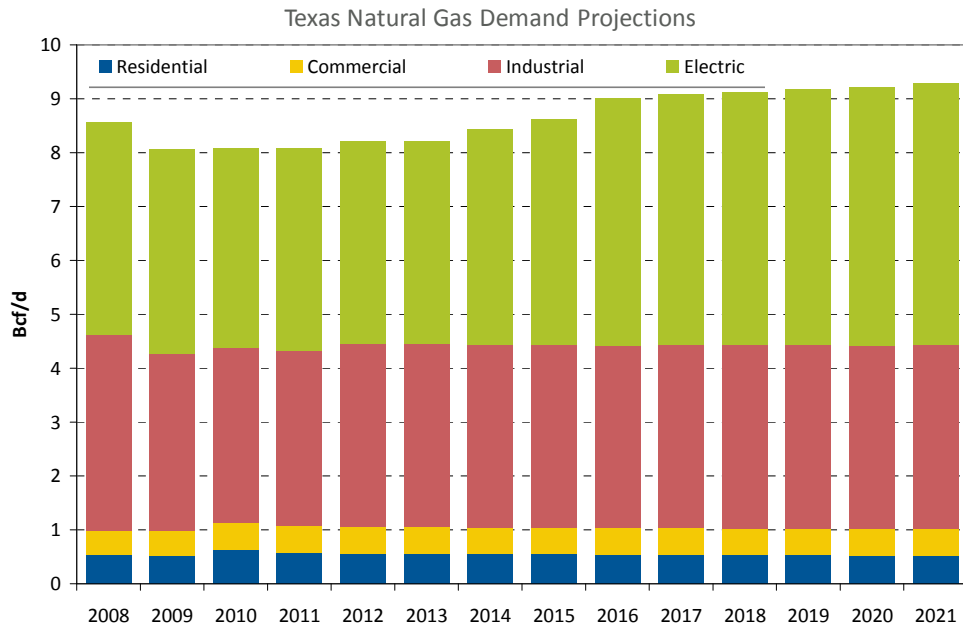


Figure 17 - Texas Natural Gas Demand Projection

- Natural gas pipelines and storage facilities are represented in detail in the fundamental supply-demand model used in this study. In order to examine the sufficiency of the pipeline grid to serve the demand of electric generators within ERCOT’s service region, electric generation facilities were grouped together on the basis of the natural gas pipelines serving them and their locations and linked (as demand nodes) to the pipeline network.
- Accuracy and precision of statistical analyses are limited by available curtailment-event data. The different curtailment scenarios considered each offered different levels of data availability and allowed varying precision in the analytical effort of this study.
- This study takes a conservative view on the risk of gas curtailment to electric generators. No mitigating measures have been incorporated in developing the results presented here. In reality, when natural gas supply or delivery is impacted, the redundancy and interconnectedness in the natural gas market generally provides consumers (including electric generators) with alternate sources and routes for natural gas supply to partially or fully serve their needs. Pipeline linepack, natural gas storage and displacement of supply from other markets could all contribute to mitigate the risk of disruption of natural gas supply to electric generators within the ERCOT service region that are presented in this study.

6.0 Risk Assessment - Results

6.1 IMPLICATIONS FROM FREEZING WEATHER

6.1.1. Probabilistic Analysis

Analysis Methodology

Each ERCOT Weather Zone was represented by a weather station for a significant population center with a long and continuous record of daily high and low temperatures (Table 4). All stations are part of the climate reference network for which data are maintained by NCDC (Appendix A – Data Sources). Additional data included precipitation and (since 1996) wind data. Analyses of daily weather for January 1981 through February 2011²³ were made for the four Weather Zones comprising the heaviest power loads within ERCOT: North Central, South Central, Coast and South. The remaining four Weather Zones (East, Far West, West and North) were analyzed at the granularity of monthly data for the same 1981-2011 period. Using heating-degree days (HDDs) as a sample attribute, it is clear that the four heavy-load Weather Zones are strongly correlated with each other (Table 5) and that the North Central Weather Zone can be used as a proxy for ERCOT in the context of freezing weather, including correlations with other gas-demand regions (Table 6).

Table 4. Weather stations used for freezing-weather analyses of ERCOT.

ERCOT WEATHER ZONE	WEATHER STATION	
	Name	WMO / WBAN ID
Coast	Houston Intl Airport	72243 / 12960
East	Tyler Pounds Field	(None) / 13972
Far West	Midland Intl Airport	72265 / 23023
North Central	Dallas Ft Worth Airport	72259 / 03927
North	Wichita Falls Municipal Airport	72351 / 13966
South Central	San Antonio Intl Airport	72253 / 12921
South	Corpus Christi Intl Airport	72251 / 12924
West	Abilene Rgnl Airport	72266 / 13962

Table 5. Winter (Dec, Jan, Feb) daily HDD correlations among the four heavy-load Weather Zones.

	NORTH CENTRAL	SOUTH CENTRAL	COAST	SOUTH
North Central	100%			
South Central	87.7%	100%		
Coast	83.9%	93.6%	100%	
South	79.7%	92.0%	91.9%	100%

²³ In support of a detailed analysis of the December 1983 freezing-weather event, historical weather data were analyzed back to January 1950. See Appendix F – December 1983 Event Simulated For 2011-2012.

Table 6. Winter (Dec, Jan, Feb) daily HDD correlations between ERCOT and other gas-demand regions.

	ERCOT	CHICAGO IL	ATLANTA GA	NEW YORK NY	WASHINGTON DC
ERCOT	100%				
Chicago IL	65.4%	100%			
Atlanta GA	51.7%	59.2%	100%		
New York NY	30.9%	57.0%	62.0%	100%	
Washington DC	36.6%	60.6%	74.3%	91.7%	100%

The significance of high winds during freezing episodes was examined using data for the North Central Weather Zone because it is the heavy-load region which is most likely to experience such conditions. Although high winds also can damage or disable electric transmission grids, which is an entirely separate risk, in the context of gas curtailments, the role of wind is expected to be limited to wind-chill effects on unshielded gas wellhead or pipeline infrastructure. Wind effects were found to be less important relative to physical temperature (Appendix B - Weather Analysis and Appendix F – December 1983 Event Simulated For 2011-2012) and did not play a role in the risk projections. The February 2011 curtailment event in ERCOT was unusual with regard to occurrence of high winds at the same time as extreme low temperatures. Indeed, the February 2011 data can be regarded as outliers²⁴ from the larger trend which shows declining winds correlated with declining winter low temperatures. If February 2011 data are omitted, there is no statistical case for winds becoming stronger as temperature falls – indeed the opposite trend prevails. Even if the February 2011 wind data are included as a worst-case scenario, the convolved freeze-wind PDF implies a level of wind-chill risk which is no more important than the risk of sub-freezing physical temperatures in the range of 25-30° F.

The sensitivity of gas production to freezing weather was evaluated by comparing production data for the Barnett Shale (north-central Texas), as obtained from the TRRC, with records of extreme daily low temperatures in the North Central Weather Zone (see details in Appendix F – December 1983 Event Simulated For 2011-2012). The causative phenomena would be freezing of water into ice or condensation of natural gas liquids (NGLs) in the product stream of wellheads without thermal protection (Figure 3).

Event Risks for freezing weather were approached in two ways:

- Calculate annualized probabilities for occurrence of extreme low temperatures (causal events) in order to understand frequency of conditions which would favor wellhead freeze-offs and therefore curtail normal gas production.
- Calculate annualized probabilities for occurrence of extreme high HDD values (causal events) in order to understand frequency of conditions which would favor unusually high demand for gas.

²⁴ For the current study, “outlier” is used to describe a point on the long tail of a PDF, i.e., an event with very low statistical probability.

In both approaches, *PDFs* were computed directly from weather data for individual locations; detailed results are provided in Appendix B - Weather Analysis .

Power-Outage Risks for freezing weather were developed by deriving *PDFs* for power (MW) loss reports (curtailment events) where freezing weather was cited as the cause whether from supply disruptions, regulatory mandated curtailments or contractually-defined curtailments. To the extent possible, data were sub-divided to examine whether sub-categories of freezing-weather events presented different levels of risk. But as discussed elsewhere (and illustrated in the Appendix B - Weather Analysis) sub-dividing data sometimes led to major increases in uncertainties of the results. Therefore, more reliance was placed on use of “undifferentiated” event data²⁵ where all freezing-weather events were treated as a single population.

All analyses shared the following assumptions about data adequacy:

- Incident statistics for 2002-2011 and for 1987-2011 are representative of the respective populations of incident rates; information missing from earlier years will not materially affect the analyses
- Weather statistics for Jan 1981 – Feb 2011 are representative of the populations of weather-related risks; future weather-related risks will follow the same statistics as for 1981-2011 and directional climate changes during 2012-2021 are assumed to be negligible

Results and Interpretations

Given the limited number of freezing-weather curtailment events documented for ERCOT, the “undifferentiated” set provides the most statistically reasonable basis for deriving event frequency. The results presented as the risk during a given winter implicitly include event statistics (Appendix B - Weather Analysis) which show:

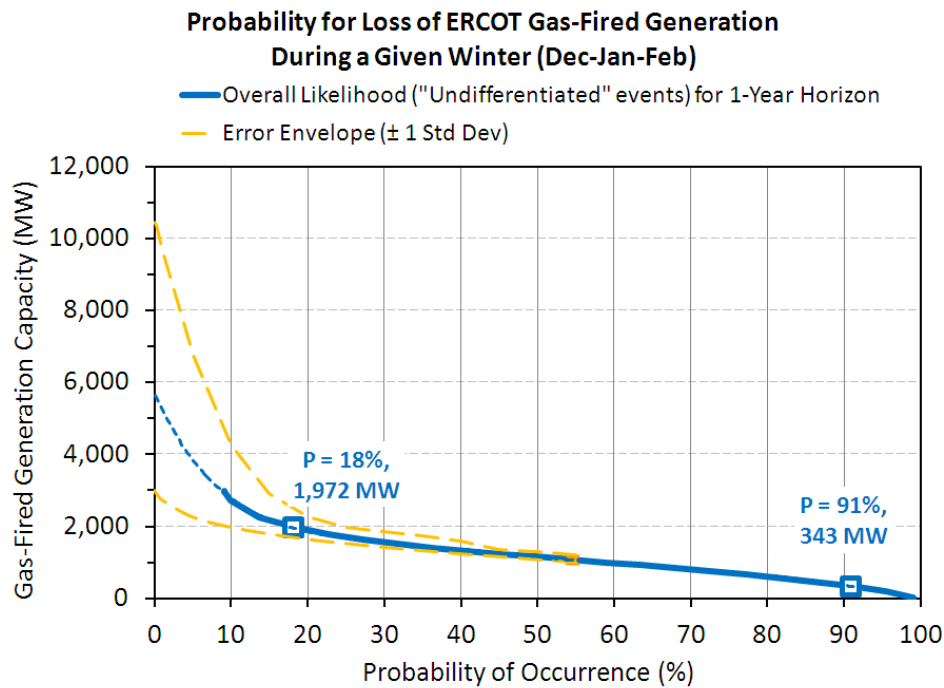
- Daily probability of 9.3% for disruptive freeze (low T ≤ 25° F)
- *PDF* mode (most likely) value of 8.8 disruptive-freeze days per winter
- *PDF* mode (most likely) value of 3.9 disruptive-freeze events per winter (where an event is a succession of one or more days defined by a particular weather episode)

²⁵ “Undifferentiated” means keeping a sample whole for input into an analysis rather than dividing it into sub-samples for separate analyses. Differentiation (sub-division) can be acceptable if the sub-samples are fundamentally different from each other and remain large enough for statistically meaningful analyses.

Error bars are derived from variations among alternative *PDFs* for the “undifferentiated” curve. The one-standard-deviation error is found to be 120 MW at the modal point (55th percentile) on the *PDF* curve²⁶ and smaller at higher probabilities (

Figure 18). But as outage probabilities decrease, the error envelope rapidly widens such that at the 1% probability mark, the predicted outage magnitude of 5,300 MW falls within an error envelope of 2,700-9,800 MW (Figure 18).

In the near term (1-Year horizon), in any given winter, there is an 18% probability of supply disruption-- from lack of gas supply or contractual/regulatory defined curtailment-- impacting about 2,000 MW generation capacity and a 91% probability of impacting about 350 MW.



²⁶ The modal point or “mode” of a *PDF* is the peak of the frequency distribution. For a Normal (bell-shaped) distribution, it coincides with the mean (average) or 50th percentile on a cumulative descending *PDF* curve such as

Figure 18. But for a non-Normal, log-based distribution, as is common in reliability models and as applies here, the mode usually occurs somewhere between the 55-70th percentiles on a cumulative descending *PDF* curve. In

Figure 18, the mode occurs at the 55th percentile.

Figure 18 Power-Outage Risk curve (freezing weather) annualized, including error envelope beginning at the 55th percentile of probability (mode or peak) of the risk distribution.

The low-end tail of the risk curve (probabilities less than 10%) in

Figure 18 is poorly constrained by the lack of quantitative historical data for large curtailments during extreme freezing-weather events. All of the candidate *PDFs* for the freezing-weather risk curve imply a steep rise of the curve – toward 5,000 MW or higher -- for outages having probabilities of 1-9% in a given winter. A separate analysis of the extreme freezing event of December 1983 (Appendix F – December 1983 Event Simulated For 2011-2012), which has an associated probability of less than 0.5% per winter, implied a worst-case outage of 11,000 MW if no mitigations were applied. The 11,000-MW mark would fall close to the upper bound of the error envelope in

Figure 18.

The temperature dependency of wellhead freeze-offs is shown in Figure 19 which was derived from analysis of Barnett Shale gas production as correlated with historical freezing-weather events . As discussed in the Appendix (Appendix F – December 1983 Event Simulated For 2011-2012), the production-loss function derived for the Barnett Shale is indicative for freezing-related gas production risks as they pertain to the gas sources upon which ERCOT generators depend. No data are available for gas-production losses during the milestone curtailment events of December 1983 and December 1989. But the production-loss function in Figure 19 predicts losses approaching 30% or more which is consistent with reports of production losses of nearly 40% across Texas during those episodes²⁷.

²⁷ FERC-NERC (2011) report, op cit.

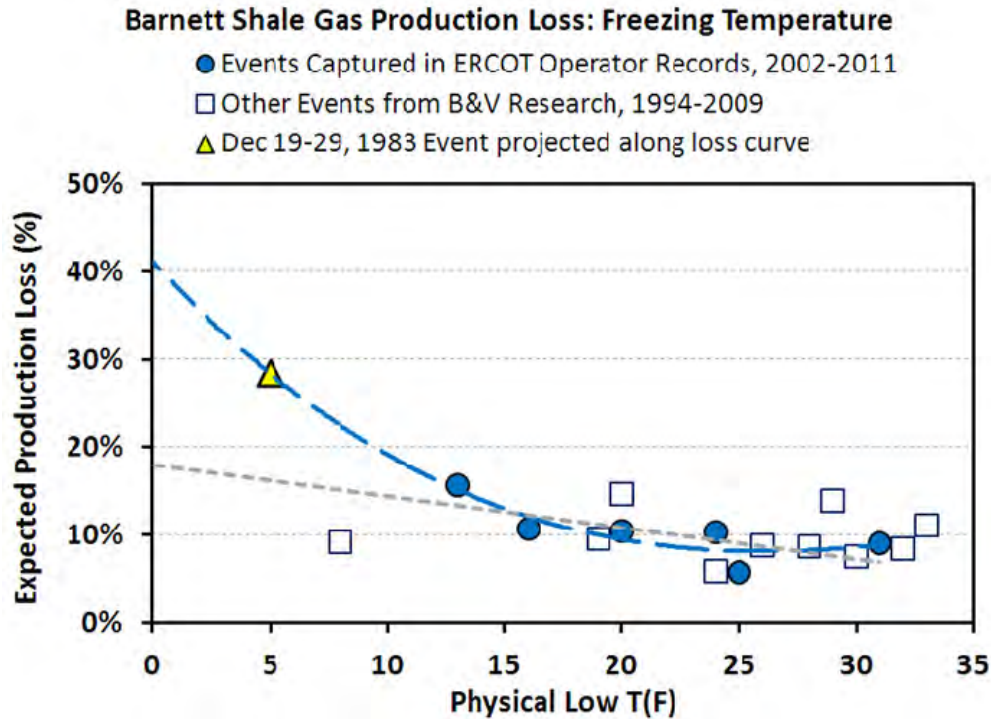


Figure 19. Loss of onshore gas production during extreme freezing events.

The 5- and 10-year risk curves shown in Figure 20 were derived from the 1-year curve using two types of scaling. First, the increase in installed gas-fired generation capacity in ERCOT, as projected by Black & Veatch, was used to scale the MW axis on the premise that the MW-at-risk metric is proportional to the number of MW in the gas-fired generation portfolio. Second, the progressive increase in use of onshore gas (with parallel decline of offshore GOM gas), as projected by Black & Veatch, was used to scale the probability axis on the premise that the amount of gas at risk of freezing-related losses is proportional to the fraction of the total gas supply which is based onshore. Uncertainties scaled upward according to shifts of the respective *PDFs* and the error envelopes for the 5- and 10-year risk horizons, respectively, generally followed the shape defined by the error envelope for the 1-year risk horizon (Figure 18), namely, expanding widely at probabilities less than 10%. For the 10-year risk horizon, there is a 1% probability of a 13,300-MW outage each winter in the absence of any mitigations (Figure 20).

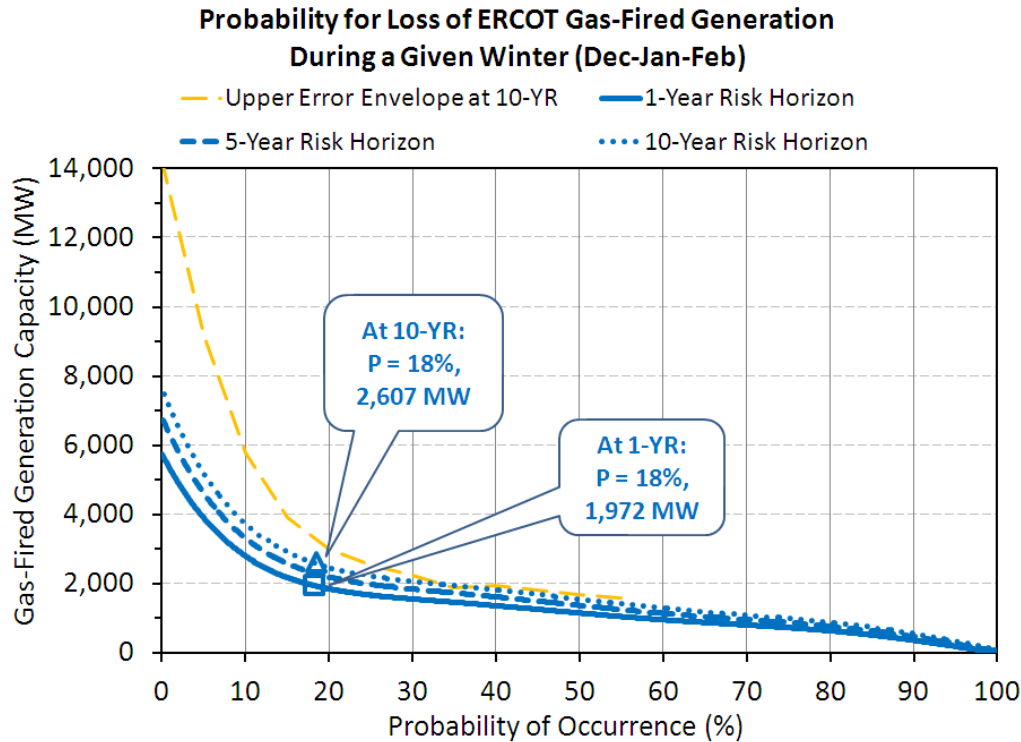


Figure 20 Power-Outage Risk curves for freezing weather with projected future trends

It is important to understand that the upward directionality of the 5- and 10-year risk curves in Figure 20 assumes that risks scale with growing exposure to known causal events but without any associated mitigations applied. Namely, thermal protection of wellheads against freeze-offs remains at historical standards as do the priorities and rationale for contractual curtailments initiated by freezing weather. In fact, both wellhead thermal protection and alternative contractual provisions offer opportunities for assuring greater reliability of gas deliveries during winter and thereby reducing the MW-at-risk magnitude.

6.1.2 Fundamental Analysis

Description of Scenario

Cold weather was found to be the leading risk factor driving curtailments within ERCOT’s service region, due to gas supply disruptions, TRRC-mandated curtailments, or contractual-driven curtailments. In addition to freeze-driven interruption of supplies, cold weather increases the competitive demand for natural gas supply for heating from the traditional residential and commercial sector markets. Interconnectivity of the Texas natural gas market with the larger North American natural gas market through the natural gas interstate pipeline grid implies that the Texas market is impacted when extreme cold weather is experienced in other parts of North America. This is particularly true of the markets in the Midwest and East Coast, which are served by the interstate pipelines transporting natural gas supply out of Texas. In order to understand the exposure to extreme cold weather in Texas and those interconnected markets, this study examined the following scenarios:

- A. Extreme cold weather in Texas alone (Cold Texas only)

- B. Extreme cold weather in Texas as well as the Midwest markets (Cold Texas & Midwest)
- C. Extreme cold weather in Texas, the Midwest markets as well as the East Coast markets (Cold Texas & Outside Markets)

The extreme cold weather considered for each scenario assumed the cold end of average daily winter temperatures corresponding to the 95th percentile for each region i.e., there is only a 5% probability that the temperature in the region will be lower than the assumed extreme cold temperature. For each scenario examined, a corresponding assumption on the increased demand for natural gas was developed. A regression analysis of cold weather (commonly measured in heating-degree days, HDDs)²⁸ against consumption was performed to determine the sensitivity of natural gas consumption to weather. As expected, natural gas consumption in the residential and commercial sectors corresponding to their heating needs exhibits high correlations with cold weather. Power generation demand and industrial demand were assumed to be less impacted by natural gas demand and this was corroborated by the regression analysis performed. The regression analysis between weather and natural gas consumption was performed on a regional basis to capture consumption characteristics unique to each of the three regions being analyzed.

Figure 21 shows the incremental daily demand assumptions in the three scenarios considered relative to normal weather demand²⁹. This incremental demand was distributed between Texas, the Midwest and the East Coast depending on the scenario analyzed.

²⁸ This study used HDD calculated as the difference between the daily average temperature and 65° Fahrenheit for every day where the daily average was colder than the 65° F reference. Although choice of reference temperature sometimes varies with geography, the 65° F reference was used both for Texas and locations outside Texas.

²⁹ Normal gas demand assumed normal HDD values for each location, respectively. See Appendix B - Weather Analysis for details.

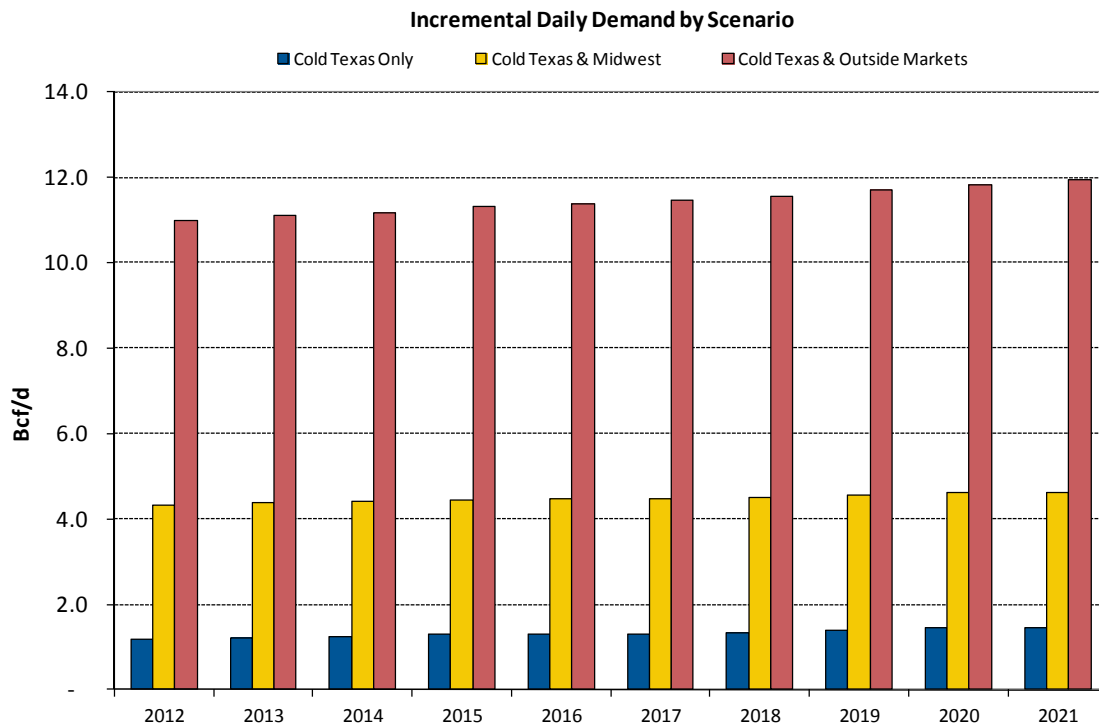


Figure 21. Incremental Daily Demand By Scenario.

The analysis in this study looked at historical freeze-offs considering data from the Barnett Shale as the best available source of recent historical data for significant onshore production in Texas. The historical well-head freeze-off information was used to determine what percentage of the Gulf region onshore production could be assumed as lost during an extreme cold weather event due to well freeze-offs as shown in Figure 22.

The level of Gulf region production lost by freeze-offs was determined using the results of the analysis above for a given low temperature. For 95th percentile cold weather in Texas, the level of onshore natural gas production curtailment implied for Texas and Louisiana is shown in Figure 22.

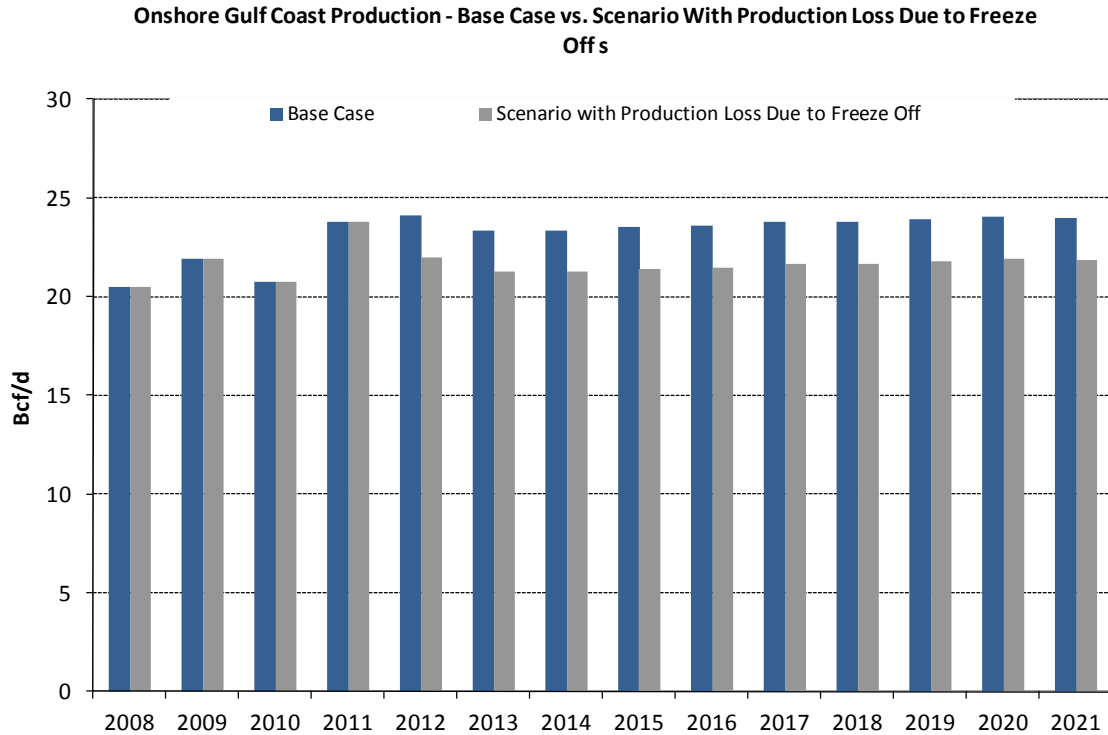


Figure 22. Onshore Gulf Coast Production and Impacts from Wellhead Freeze-offs.

Risk Assessment

The study examined the adequacy of natural gas pipeline infrastructure to meet demand in scenarios of extreme cold weather. Study results revealed that natural gas pipeline infrastructure, as represented within the fundamental network model, appears to be adequate and does not act as a constraint during the extreme weather events examined. It should be noted that localized and isolated incidents of constraints can occur on occasion at the utility or pipeline level.

Below are a series of charts that show pipeline utilization along the main corridors of natural gas transportation within ERCOT. The utilization on intrastate pipelines is shown here since they serve the majority of load in Texas. As seen in these results, the utilization of the intrastate natural gas pipelines in aggregate remains below 70% in the scenarios examined. Those results include analyses of gas hauls along transportation paths from Houston to Beaumont (

Figure 23), from North Texas to Houston (Figure 24), from West Texas to North Texas (Figure 25) and from South Texas to Houston (Figure 26). This analysis applies to the major gas pipelines and it should be noted that individual pipelines could periodically experience constraints during periods of high demand from consumers. Each pipeline corridor, however, has sufficient capacity to deliver natural gas to meet the increased demand.

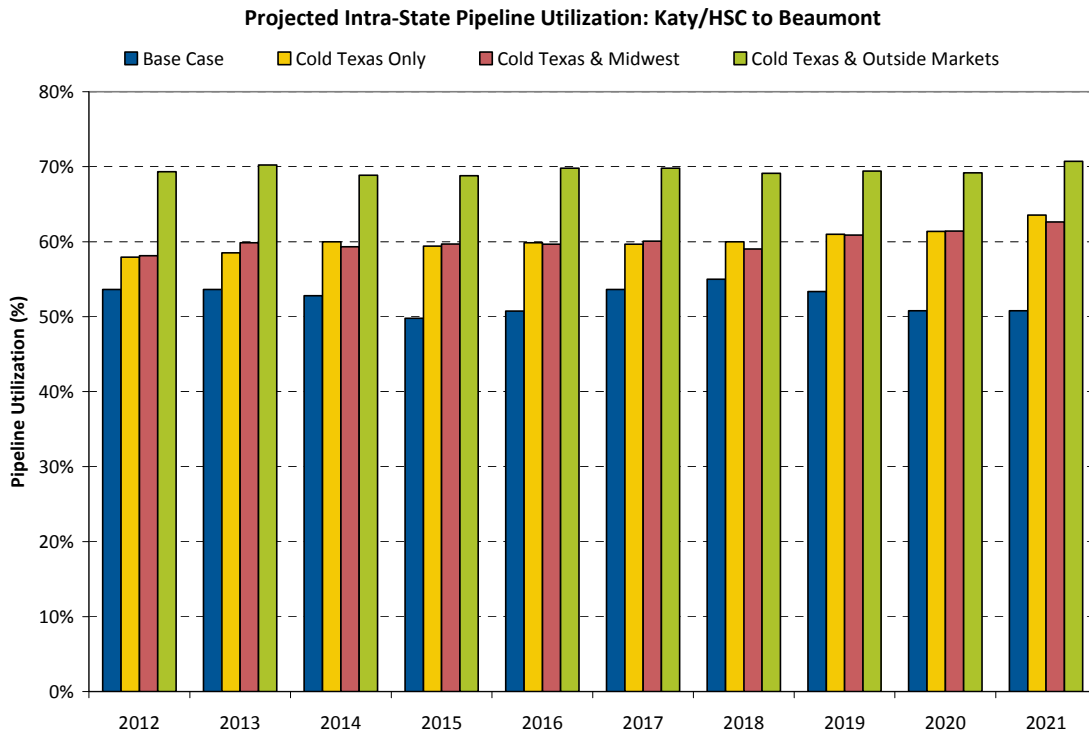


Figure 23 Projected Intrastate Pipeline Utilization, Houston to Beaumont

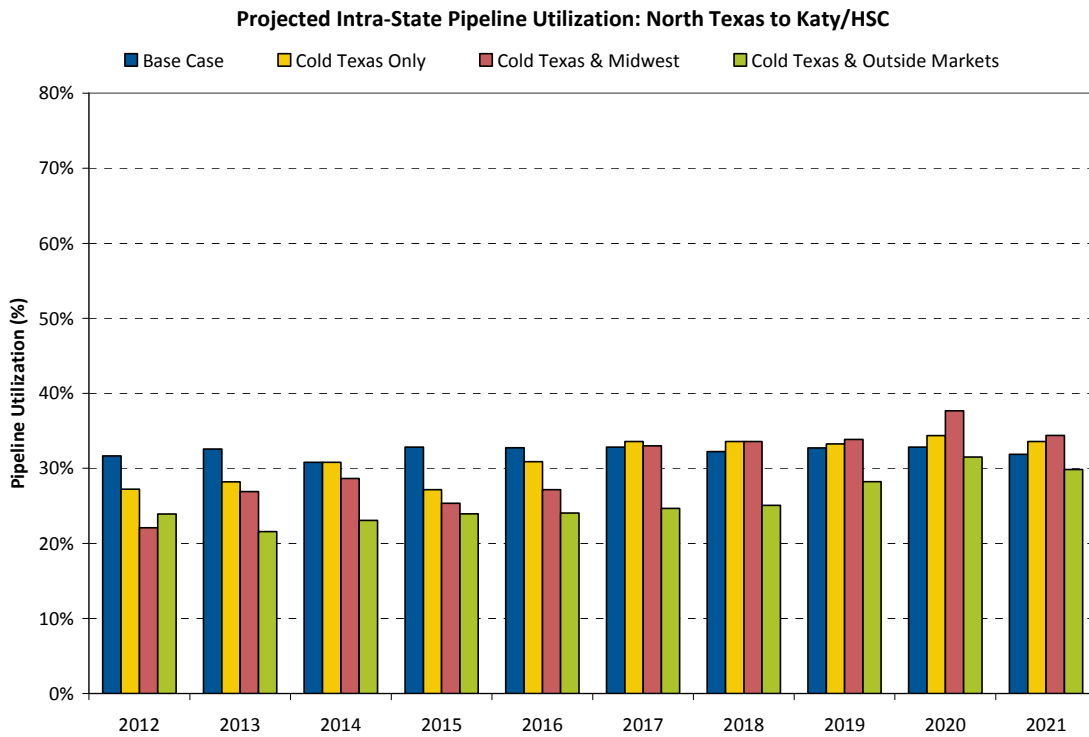


Figure 24. Projected Intrastate Pipeline Utilization, North Texas to Houston.

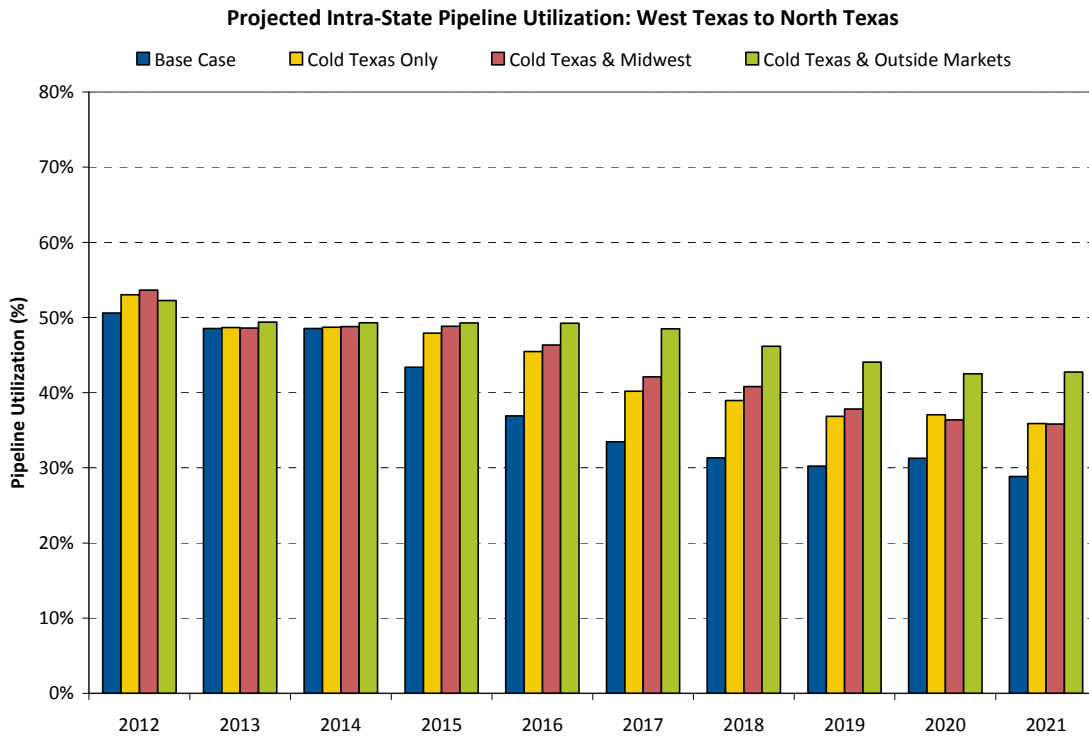


Figure 25. Projected Intrastate Pipeline Utilization, West Texas to North Texas.

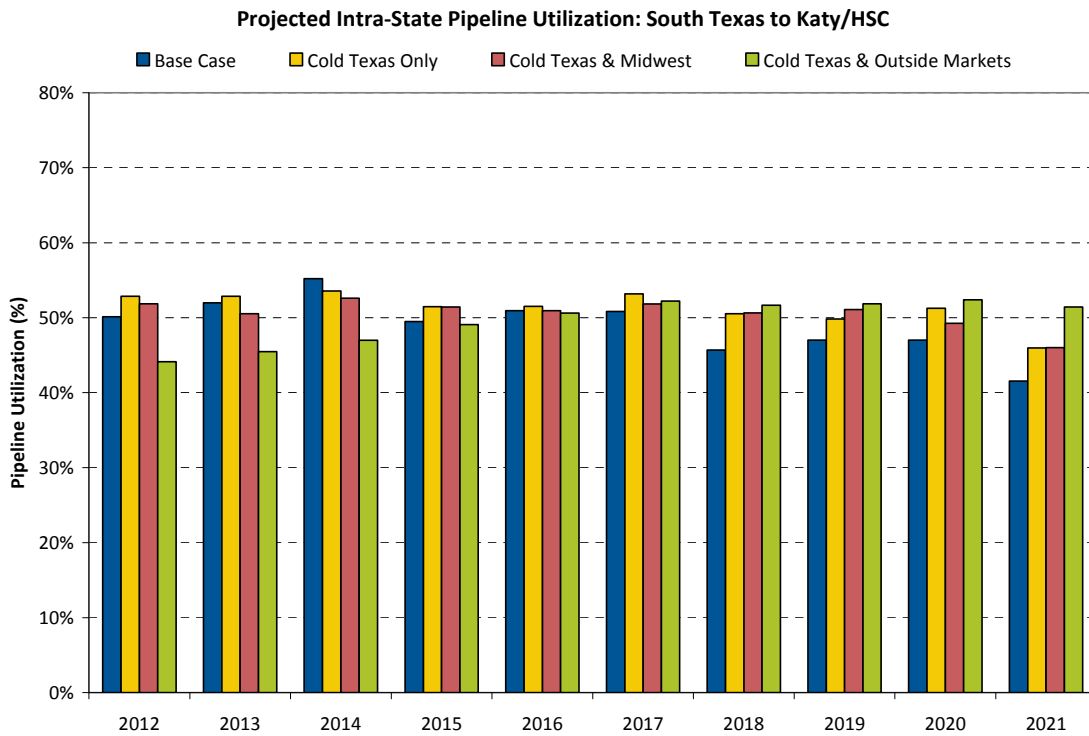


Figure 26. Projected Intrastate Pipeline Utilization, South Texas to Houston.

6.2 IMPLICATIONS FROM PIPELINE DISRUPTION

6.2.1. Probabilistic Analysis

Analysis methodology

Research revealed only 10 incident reports where pipeline issues³⁰ were cited as the cause of loss of gas volumes or gas-fired power generation. But another 54 incident reports, with no specific causes identified, were classified as “Unknown” causes but inferred to be pipeline-related³¹ (Figure 27). Therefore the combined data set, when treated as a single “undifferentiated” sample of the population, was numerically sufficient to support analysis in terms of power outages. Gas-curtailement incidents reported as MMBtu/d (for example, right-hand chart in Figure 27) were converted to power-generation losses (MW)³² although attribution to specific pipelines generally was not possible. Some gas curtailments attributed to pipeline interruptions were reported explicitly with power (MW) impacts but many pipeline-related incident reports quoted gas volumes curtailed (MMBtu/d). In this case, Black & Veatch found it necessary to convert gas to power (using known characteristics of ERCOT gas-fired generation) to derive the imputed impact on generation. One aspect of that conversion process is the implicit assumption that the curtailed gas was required for power generation and that no alternative supply was available. It does not allow for fuel switching or for redundancy in pipeline service. In that context, the pipeline-outage risk curves might be considered as conservative in the sense that they estimate toward the high end of arguable risk magnitudes.

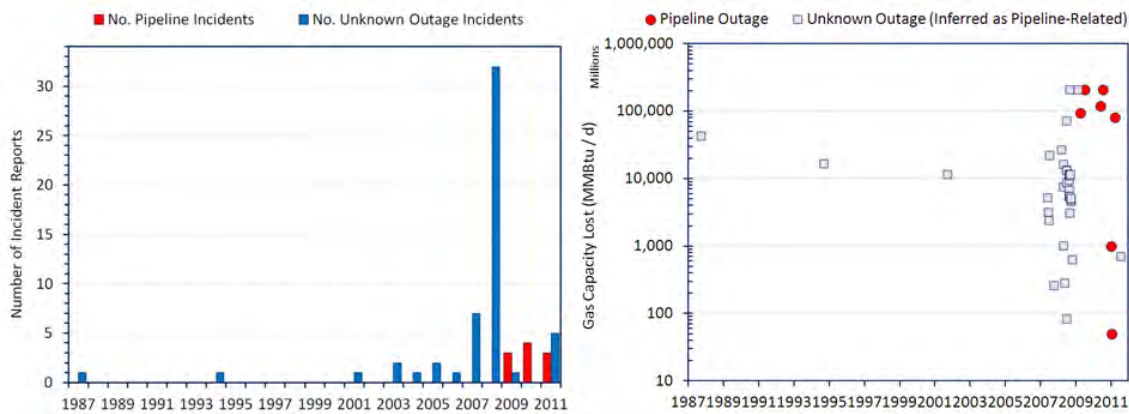


Figure 27. Definition of the pipeline incidents available for risk analysis.

Results and interpretations

On a 1-year horizon, there is a 5% chance to lose 500 MW (about 1% of ERCOT gas-fired generation) as a consequence of pipeline outages (Figure 28). Error bars were derived from

³⁰ Incident reports cited a variety of different occurrences including line ruptures, compressor repairs and other maintenance. Specific pipelines were mentioned in some, but not all, cases.

³¹ Curtailments where cause was “Unknown” (i.e., not identified in the incident report) were checked against weather conditions on their respective dates. Especially for summer incidents, where neither tropical cyclones nor severe thunderstorms occurred, pipeline-related factors were the most likely default explanations.

³² To convert gas (MMBtu/d) to power generation (MW), assumptions included a heat rate of 7.5 MMBtu/MWh, 8 hours of generation during a day and a total gas-fired capacity of 47 GW.

variations among alternative PDFs. On a one-standard-deviation basis, the uncertainty is ± 112 MW at a probability of 10% and ± 677 MW at 0.5% probability.

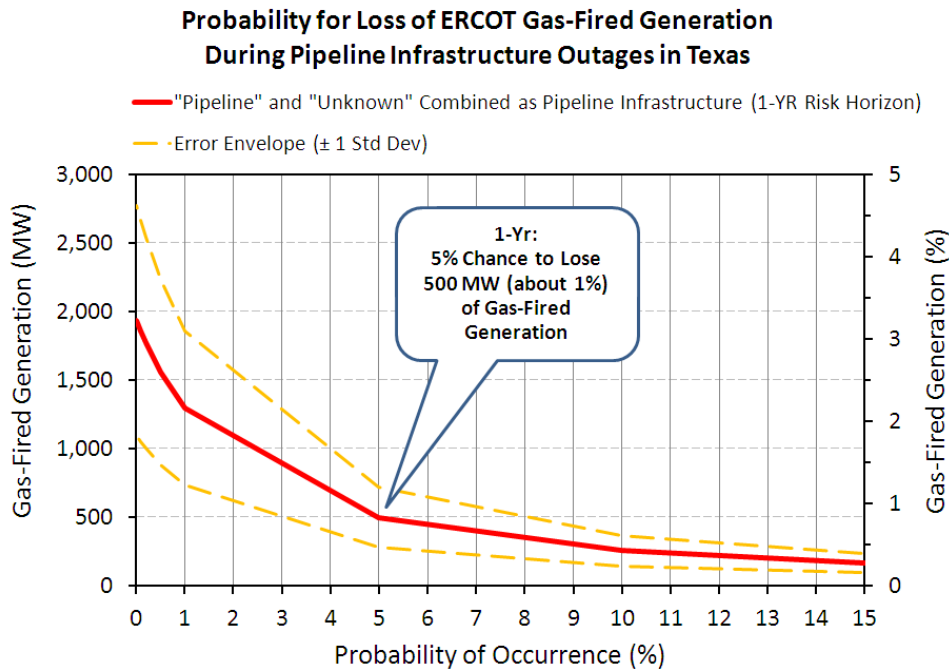


Figure 28. Power-Outage Risk curve for pipeline infrastructure issues.

Going forward, the premise adopted was that there are no net changes to risks at the 5-year and 10-year horizons (i.e., directional factors for risk change are assumed to be mutually offsetting) - aging infrastructure might increase risks but more strenuous regulations (and system upgrades) are expected to decrease risks. Although pipeline engineers recognize that failure rates scale upward with loss of pipeline integrity (predominantly through aging) and with growth of total pipeline mileage³³, improved practices for inspection and corrosion control are significant mitigations against pipeline failures. As discussed below, there are significant initiatives underway that focus on improving the safety and reliability of the natural gas pipeline grid and in that context, the 5-Year and 10-Year pipeline-outage risk curves might be considered as conservative in the sense that they estimate toward the high end of arguable risk magnitudes.

Effective February 14, 2004, US DOT – Pipeline and Hazardous Safety Administration (PHMSA) put into effect its revised pipeline Integrity Management Plan (IMP) requirements for the operators of natural gas transmission pipelines. PHMSA's goal was to improve the overall integrity of pipeline systems and reduce risks. To adequately evaluate risk, it is necessary to identify and evaluate the physical and operational characteristics of each individual pipeline system. and to that end, IMP programs were created with the following objectives:

³³ Crawley F. K., Lines I. G. and Mather J. (2003). Oil and gas pipeline failure modeling, *Trans IChemE, Vol 81, Part B,* January 2003, p. 3-11.

- Ensuring the quality of pipeline integrity in areas with a higher potential for adverse consequences (high consequence areas);
- Promoting a more rigorous and systematic management of pipeline integrity and risk by operators;
- Maintaining the government's prominent role in the oversight of pipeline operator integrity plans and programs; and
- Increasing the public's confidence in the safe operation of the nation's pipeline network.

Operators of the transmission pipelines were operating under their individual IMPs when, in 2010, a series of natural gas incidents that resulted in death and / or property damage raised the Nation's discussion regarding pipeline safety to new heights.

The level of scrutiny of pipeline operators increased dramatically at both the Federal and State level.

For example, on January 10, 2011, PHMSA issued an advisory bulletin (ADB-11-01) to natural gas pipeline operators in which it instructed operators to take appropriate actions to ensure its records for transmission pipeline maximum operating pressure (MAOP) are "traceable, verifiable and complete."

In April 2011, the American Gas Association (AGA) and its members supported this effort by developing and publishing a white paper which served two primary purposes:

1. Enlightening all parties so that there is a better understanding of how MAOPs were originally determined by pipeline operators and what type of records are useful in verifying this determination; and
2. Providing guidance for what documentation is reasonable to expect a natural gas pipeline operator to have in responding to concerns identified in the PHMSA advisory bulletin.

On August 25, 2011 PHMSA issued a proposed rulemaking "considering whether changes are needed to the regulations governing the safety of gas transmission pipelines. In particular, PHMSA is considering whether integrity management requirements should be changed, including adding more prescriptive language in some areas, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. Among the specific issues PHMSA is considering concerning IM requirements is whether the definition of a high-consequence area should be revised, and whether additional restrictions should be placed on the use of specific pipeline assessment methods."

And on November 29, 2011 PHMSA proposed to make "miscellaneous changes to the pipeline safety regulations. The proposed changes would correct errors, address inconsistencies, and respond to rulemaking petitions. The requirements in several subject matter areas would be affected, including the performance of post-construction inspections; leak surveys of Type B onshore gas gathering lines; the requirements for qualifying plastic pipe joiners; the regulation of ethanol; the transportation of pipe; the filing of offshore

pipeline condition reports; the calculation of pressure reductions for hazardous liquid pipeline anomalies; and the odorization of gas transmission lateral lines”.

In addition to what is happening at the Federal level, discussions are taking place within individual States between the State Public Service Commissions and the gas utilities that they oversee regarding potential changes in pipeline integrity rules and requirements.

6.2.2. Fundamental Analysis

Description of Scenarios

Pipeline disruptions were the second most common drivers of gas curtailment incidents reviewed in the historical curtailment data. In the fundamental analysis of pipeline disruptions, we examined the ability of the interconnected gas pipeline grid to supply natural gas to electric generators in the event of an unexpected failure on a given pipeline. Disruption of scheduled natural gas pipeline service can occur due to causes such as corrosion, outside force damage (including excavation), and unscheduled maintenance. Redundancy in the pipeline capacity serving a given generation facility can help mitigate the risk of gas supply curtailment caused by pipeline disruption.

As a stress test in the fundamental analysis, this study examined the impact of a pipeline disruption of increasing severity on the pipeline serving the largest number of electric generation facilities within ERCOT’s service region. Based on the results of the survey of electric generators that was conducted as part of this study, twenty-four electric generators are served by the Kinder Morgan Tejas Pipeline. Our analysis reduced the capacity on this pipeline by 10%, 20% and 40% successively to examine the flexibility in the natural gas pipeline grid as well as in the electric generators’ supply portfolios to be served in the absence of this capacity. Figure 29 shows the curtailed volumes assumed for each of the scenarios.

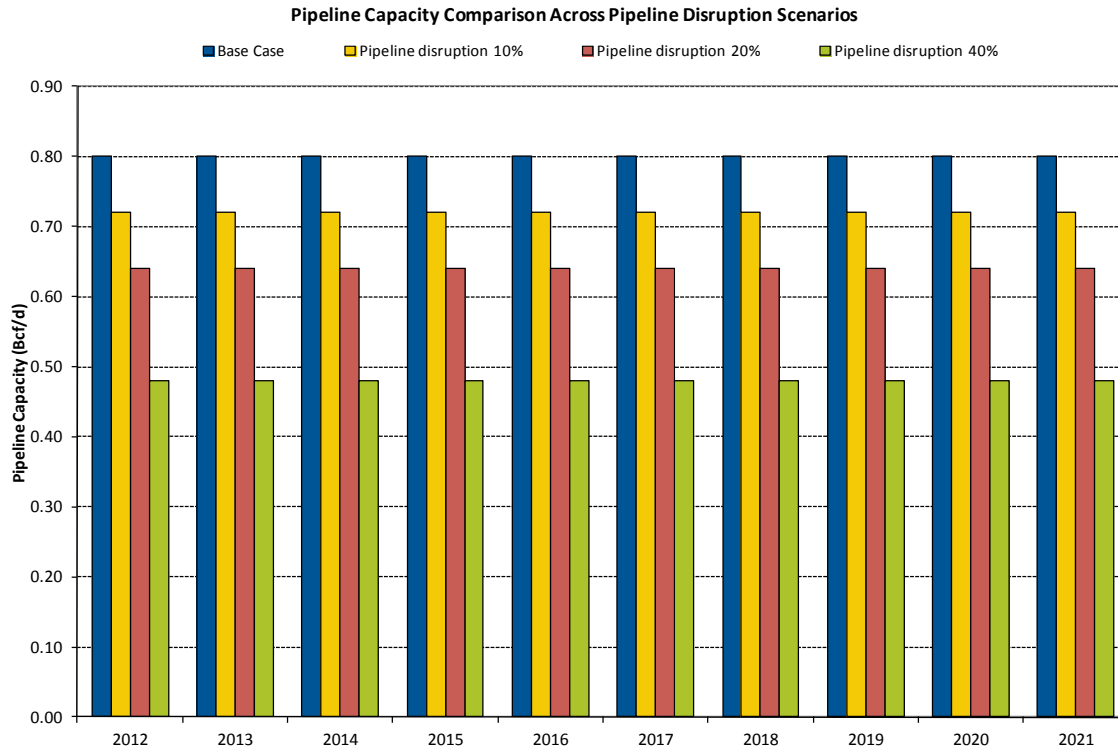


Figure 29 Pipeline Capacity Comparison Across Pipeline Disruption Scenarios

Risk Assessment

A pipeline disruption is represented in the fundamental model by reducing a part of the stated capacity of the pipeline. Redundancy in the natural gas pipeline grid and in transportation options available to an electric generator lead to the result that other pipelines (primarily, Kinder Morgan Texas Pipeline in the scenarios analyzed) experience increased utilization as they work to serve the gas demand needs of the customers stranded by failure of the original pipeline. Curtailment of natural gas supply was not observed in this scenario. Figure 30 shows the ramp up of volume transported on Kinder Morgan Texas to serve customers requiring natural gas supply.

Although the fundamental model indicates seamless transition in the market to a different pipeline that is capable of serving the market, it should be noted that commercial arrangements and market inefficiencies could create challenges in achieving this theoretical re-routing.

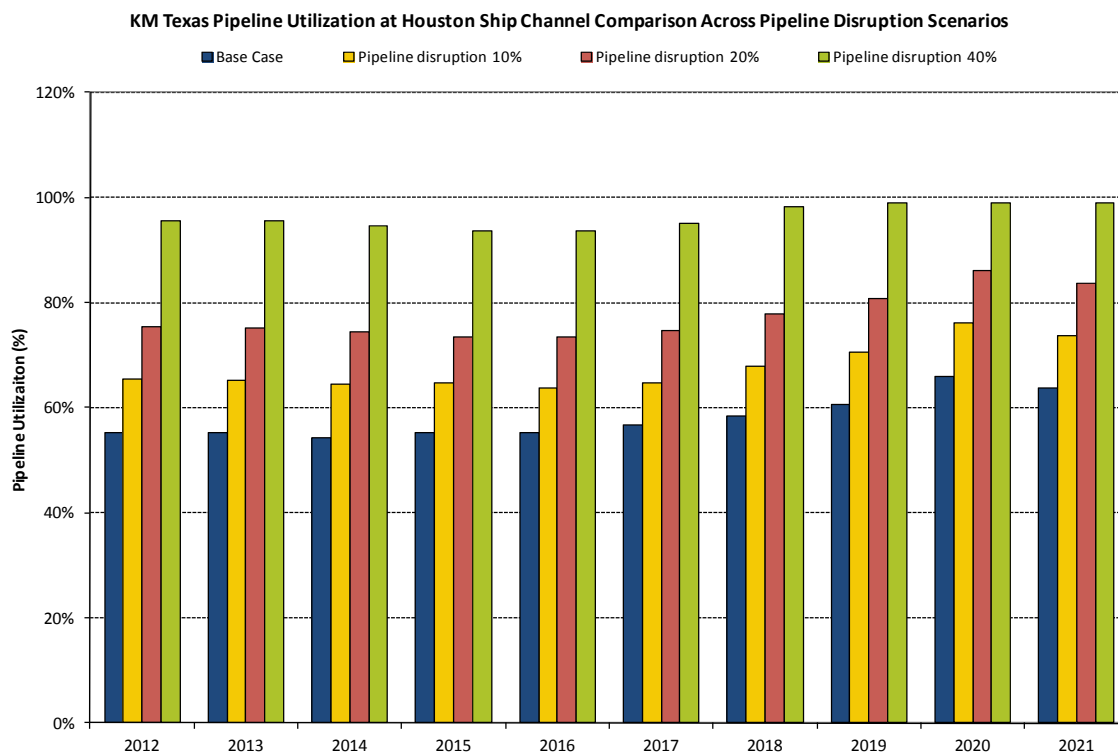


Figure 30. Indicative Pipeline Utilization Across Pipeline Disruption Scenarios.

As noted in Section 4, the survey of electric generators within ERCOT that was conducted as part of this study revealed that 87% of survey respondents have access to natural gas supply from multiple pipelines. Those pipeline interconnects enable redundancy in supply with over 65% of the respondents indicating access to pipeline capacity equivalent to more than 150% of their peak needs. The access to multiple pipelines and interconnect capacities equivalent to multiples of estimated peak needs contribute to reliability for electric generators in the event of disruption on an individual pipeline.

6.3 IMPLICATIONS FROM TROPICAL CYCLONES

6.3.1. Probabilistic Analysis

Analysis methodology

Unlike the situation for freezing-weather events, there were only two documented cases of gas curtailments to electric generators caused by tropical cyclones³⁴. Therefore, the direct development of a *PDF* for Power-Outage Risk was not possible. The alternative pathway was to first develop Event Risk statistics for tropical cyclones and then translate into risk of GOM gas-supply losses and equivalent power-generation losses (5.1 Summary of Approach).

³⁴ Additional tropical cyclone causal events occurred during the period of analysis but they fell outside the span of ERCOT curtailment records. See 5.1 Summary of Approach.

Black & Veatch found it necessary to convert gas to power (using known characteristics of ERCOT gas-fired generation)³⁵ to derive the imputed impact on generation. One aspect of the conversion process is the implicit assumption that the curtailed gas was required for power generation and that no alternative supply was available. It does not allow for fuel switching or for redundancy in gas supply. In that context, the tropical cyclone risk curves might be considered as conservative in that they estimate toward the high end of arguable risk magnitudes.

For the analysis period of 1981-2011, there were a total of 111 tropical cyclones with 25 making landfall in Texas. Disruption of gas infrastructure by coastal flooding, which is an additional known risk, was not quantitatively analyzed in view of sparse data in the available span of records for documented gas curtailments.

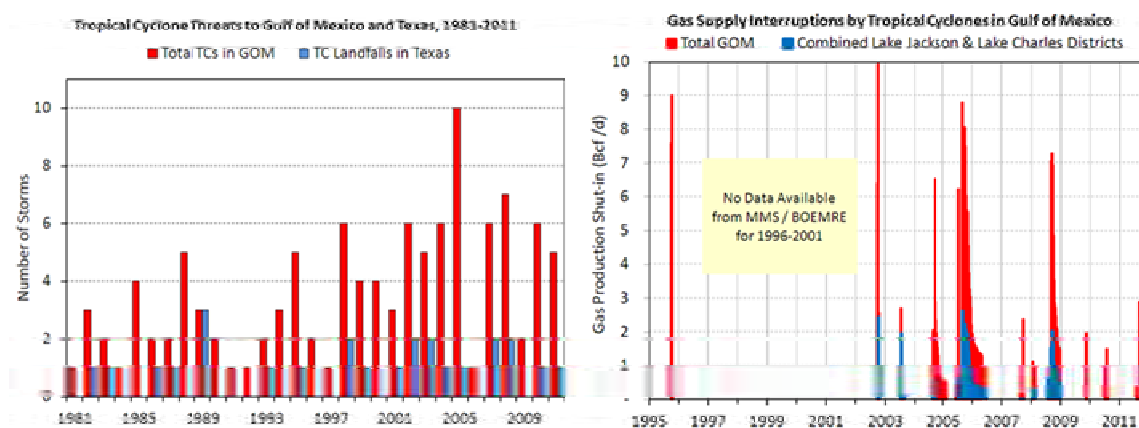


Figure 31 Observed frequency of tropical cyclones and their impacts on gas production in the Gulf of Mexico

Results and Interpretations

Compared with the total volume of gas required for ERCOT power generation, the proportion of gas obtained from GOM offshore production is small. Black & Veatch estimated that less than 5% of the total ERCOT gas consumption depends on GOM production. Therefore, tropical cyclone impacts on ERCOT’s power generation are relatively small (Figure 1).

Going forward, the 1-year risk curve was the initial model for long-baseline adjustments. Downward adjustments were made for expected shift toward onshore gas supplies; therefore, the likelihood (probability) element trended downward. Upward adjustment was made for expected growth of gas-fired capacity; portfolio exposure therefore trended upward. Overall, the risk of losing gas-fired generation dependent on GOM gas declines because shift to onshore gas happens faster than growth of gas-fired capacity. There is a 13% probability of losing 1,000-MW of generation in Year-1 but only a 3% probability of losing 1,000-MW of generation in Year-10.

³⁵ To convert gas (MMBtu/d) to power generation (MW), assumptions included a heat rate of 7.5 MMBtu/MWh, and 8 hours of generation during a day.

Error envelopes were derived from variations among alternative PDFs. On a one-standard-deviation basis, uncertainties of generation losses at the level of 5% probability were derived as 209 MW (1-Year), 166 MW (5-Year) and 105 MW (10-Year) in any given Atlantic Basin tropical-cyclone season (June through November).

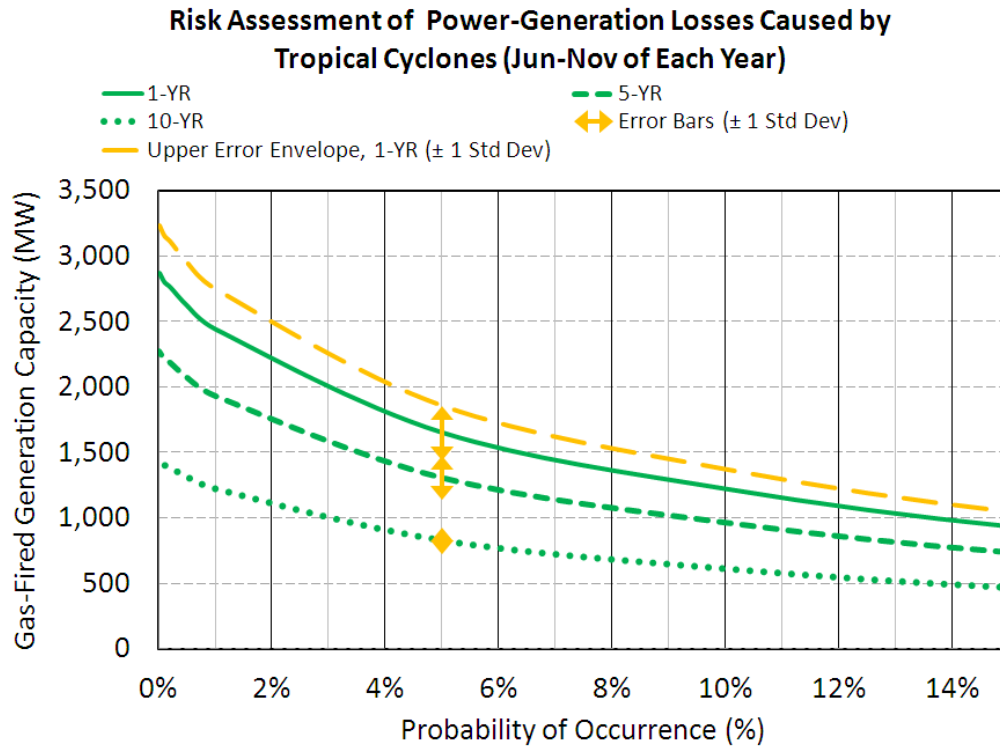


Figure 32. Power-Outage Risk curves derived for annualized tropical cyclone frequencies.

Tropical cyclone risks further are moderated in a way that distinguishes tropical cyclones from freezing weather. Namely, landfall of a major tropical cyclone can cause temporary demand loss as well as supply interruption. The most conspicuous example is from Hurricane Ike which made landfall at Houston on Sep 13, 2008 (Figure 33). CenterPoint Energy required 18 days to fully restore power to customers whereas pipeline disruptions were corrected within 10 days -- so gas supply came back before power for many users. Major industrial impacts at Houston Ship Channel implied that without electric power, the ability to use gas was impacted and gas demand during the event was reduced.

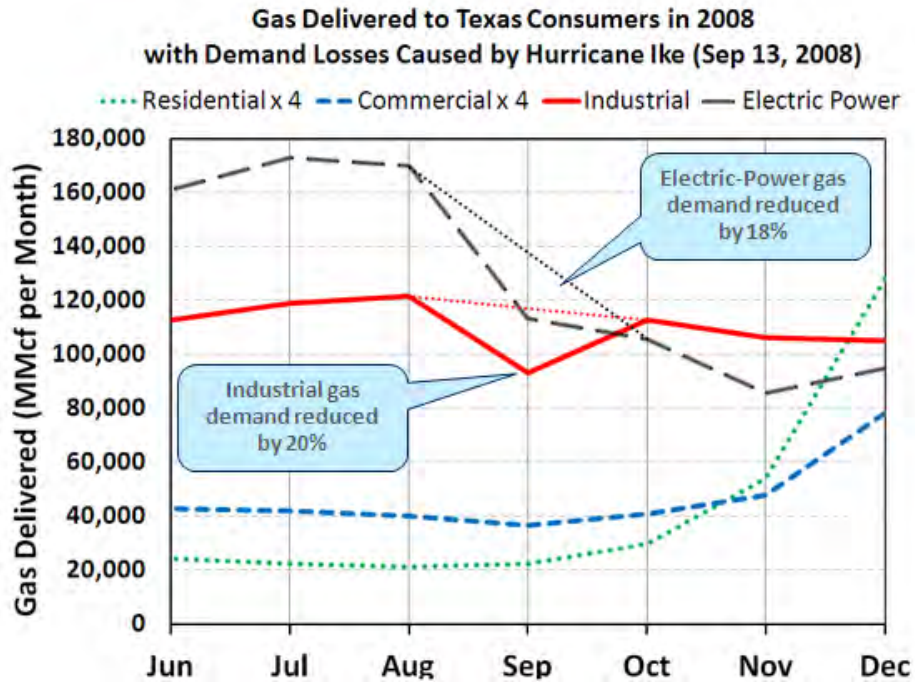


Figure 33. Temporary gas demand destruction caused by Hurricane Ike in 2008. Data from Energy Information Administration.

6.3.2. Fundamental Analysis

Description of Scenarios

The fundamental analysis of the risk of disruption of natural gas supply to electric generators within ERCOT’s service region caused by tropical cyclones examined the impact of production shut-ins in the Gulf of Mexico driven by tropical cyclones. The level of production shut-in that was examined was based upon the probabilistic analysis of the level of production losses experienced historically due to tropical cyclones. As noted in the probabilistic analysis, for the analysis period of 1981-2011, there were a total of 111 tropical cyclones with 25 making landfall in Texas. Figure 34 shows the gas shut-in risk assessment of the impact of tropical cyclones on GOM offshore production. For example, in any given year, at some time during the tropical-cyclone season, there is a 45% chance of losing 10% of GOM gas production and approximately a 5% chance of losing roughly 50% of GOM gas production. Based on historical data, the highest level of expected loss would be at about 80% of GOM production – but with a likelihood of only about 0.1%.

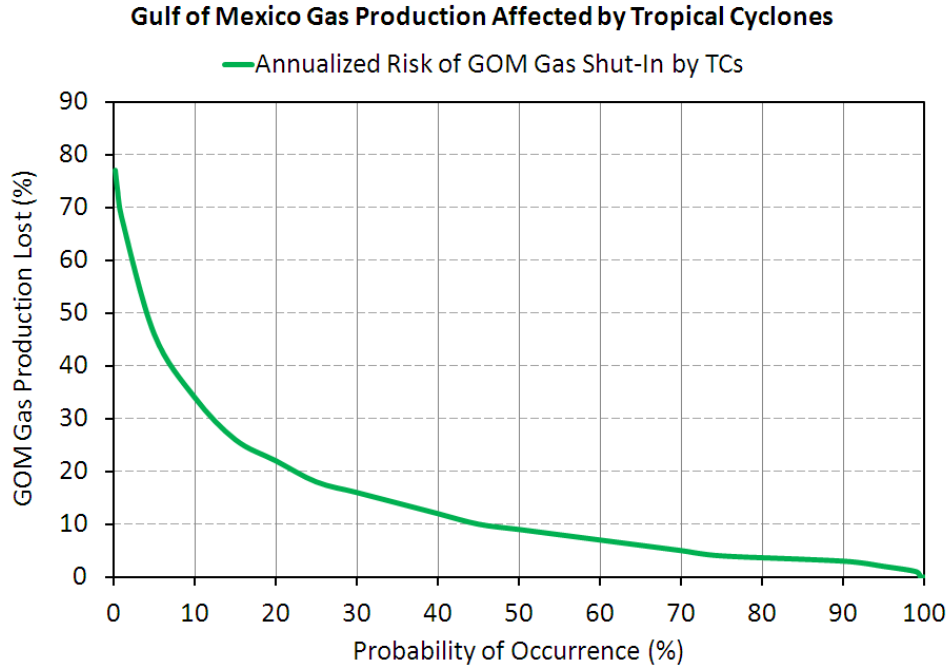


Figure 34. Gulf of Mexico Gas Production Affected by Tropical Cyclones.

The study examined three scenarios of GOM offshore production shut-ins corresponding to the 90th, 95th and 99th percentile of the event risk analysis shown, respectively curtailing 34%, 46% and as much as 68% of the GOM offshore production. The fundamental analysis examined the market reponse to the loss of this level of supply and implications for Texas consumers. Figure 35 shows the offshore production disruption driven by shut-ins due to tropical cyclones.

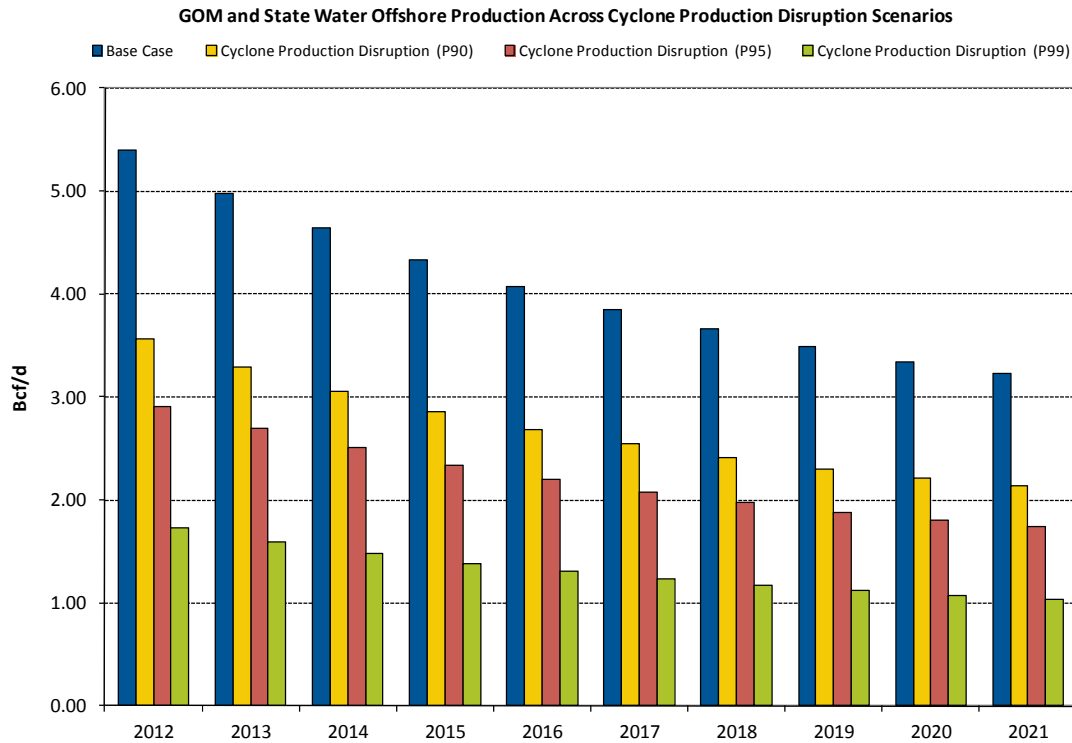


Figure 35. Loss of Gas Production Anticipated for Tropical Cyclone as the Causal Events.

It should be noted that the impact of onshore flooding is not considered in this analysis. Onshore flooding due to excessive rainfall when tropical cyclones make landfall may decrease available gas supply if natural gas processing facilities are impacted by flooding and therefore unavailable to produce pipeline-quality gas. Onshore flooding can also have the impact of decreasing demand, especially in the industrial sector at the Houston Ship Channel.

Risk Assessment

The primary result of the fundamental analysis is that there is minimal disruption of gas supply within Texas because much of Texas demand is served by local onshore production. Offshore production is only between 2%-4% of the total production in Texas and loss of this volume of natural gas does not constrain access to supply for Texas consumers. The scenarios of tropical cyclones examined in the fundamental model showed sufficiency of both pipeline infrastructure as well as natural gas supply to fully meet the demands of all consumers including electric generators within Texas.

Appendices

APPENDIX A – DATA SOURCES

Figure A1 summarizes the overall process of collecting and sorting information about gas curtailments affecting ERCOT. Details of each data source are described in the following paragraphs. As shown in the process flow, the research began broadly to assure that information relevant to ERCOT was captured from a wide variety of likely sources. The filtering process paid attention to whether an incident report stated unambiguously that gas curtailment was involved and whether a specific cause was cited for the curtailment. Incident reports which landed in the filtered bin labeled as “Yes” were retained for subsequent analyses whereas those landing in the filtered bin labeled as “Maybe” were excluded from the risk analyses. Within the “Yes” bin, causes of curtailments were tallied according to the causes stated in the incident reports or, if no cause was explicitly stated, by inference based on (a) cross-checking independent weather reports for possible weather causes, and (b) comparison with documented causes in other incident reports from closely related dates and places.

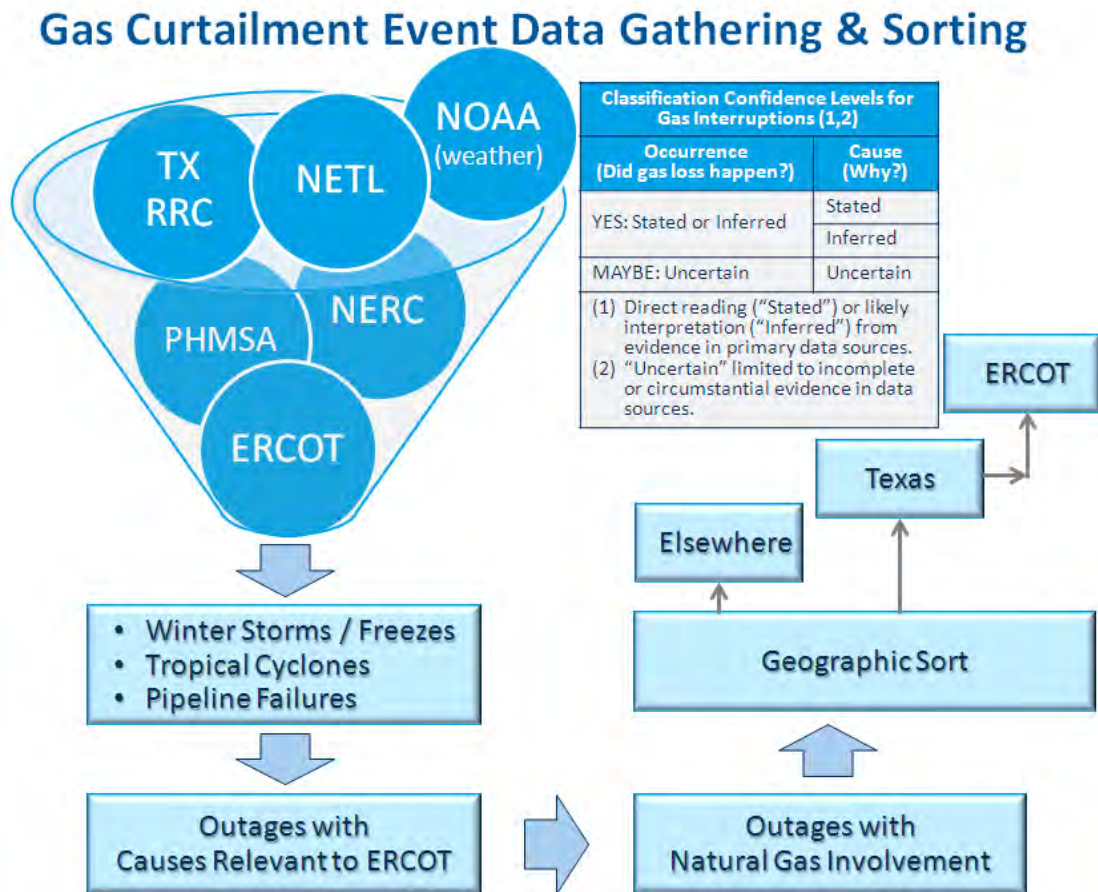


Figure A36: Process used to collect and sort information about gas curtailments.

ERCOT. Three sources of information from ERCOT were used. First, Operator logs provided by ERCOT, for the years 2002-2011, were reviewed with special attention to the "Comments" field to determine the role of gas curtailment in each log entry. Black & Veatch eliminated (from the pool of incidents to be analyzed) log entries where gas curtailment was locally isolated (for example, failed gas valves at power plant) or where a forecasted gas curtailment later was canceled. For log entries not eliminated by those criteria, incident reports were translated into "events" by combining log entries for successive dates where comments indicated a continuous string of gas-curtailed days related to a common causal episode.

Second, information was gathered from responses to data requests returned by ERCOT Power-Generation Entities in October 3-5, 2011. Attention was focused on the "Curtailment" section of each response to determine whether a specific cause was cited or whether context allowed an inference of cause. Most attributions of causes were brief and usually lacking in specifics. Examples included "Fuel supply problems" or "Lack of fuel".

Third, ERCOT Monthly Operations Reports (EMORs), for January 2004 to July 2007, were reviewed with focused attention on gas-related comments. Isolated reports of gas curtailments were mentioned in the reports and noted in the database.

NERC. NERC System Disturbance Reports, for the years 1992-2009, were reviewed for information about electric generation curtailment events in the USA. During review, the focus of attention was on outages at gas-fired generators.

NETL. NETL Electric Disturbance Events (OE-417 Reports), for the years 2000-2011, were reviewed with focused attention on any incidents in ERCOT, including but not limited to gas curtailments. The records also were searched specifically for incidents involving gas curtailments (either ERCOT or other regions).

NOAA. All weather data used in this study were acquired directly from agencies within the US National Oceanic and Atmospheric Administration (NOAA), including the National Climatic Data Center (NCDC), National Hurricane Center (NHC) and Storm Prediction Center (SPC) which are recognized as the keepers of their respective data types for official US records. SPC data were used to cross-check outage reports which referenced severe weather as the cause of some power system outages. NHC data (quality-controlled HURDAT format) were used to construct event frequencies for tropical cyclones (hurricanes, tropical storms and tropical depressions) which affect natural gas production from the Gulf of Mexico as well as coastal flooding threats to energy infrastructures. NCDC data for 1981-2011 were key to deriving probabilities for extreme freezing events in Texas (including relationships between wind speed and temperature) as well as in gas-demand centers outside of Texas, including the Midwest (represented by Chicago IL) and the Atlantic Coast (represented by New York NY, Washington DC and Atlanta GA). Quality-controlled data included RCO and QCLCD data formats maintained by NCDC. All temperatures were analyzed in degrees Fahrenheit (°F) and all heating-degree days (HDDs) were calculated to the nearest 0.5 unit for a reference temperature of 65° F. Winds speeds were analyzed in miles per hour and precipitation in liquid-equivalent inches.

PHMSA. US Department of Transportation (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA) Data & Statistics were reviewed with focus on gas pipelines.

TRRC. The Railroad Commission of Texas, in response to a data request facilitated by ERCOT, provided (Oct 2011) a brief summary of gas-curtailement events recognized by the TRRC.

APPENDIX B - WEATHER ANALYSIS

Sub-Freezing Temperatures and Heating-Degree Days (HDDs). The following charts summarize the tabular forms of PDFs derived for winter weather in ERCOT and for demand centers outside of Texas:

Daily Sub-Freezing Extreme Low Temperatures in ERCOT Weather Zones*				
Percent Probability of Occurrence on Any Given Winter Day (Dec, Jan, Feb - all equal)				
Temperature Milestone (°F)	North Central	South Central	Coast	South
≤ 32	28.7%	15.9%	12.1%	4.8%
≤ 30	21.6%	11.6%	8.1%	3.2%
≤ 25	9.3%	3.9%	2.4%	0.9%
≤ 20	3.7%	1.0%	0.5%	0.2%
≤ 15	1.4%	0.2%	0.1%	0.0%
≤ 10	0.5%	0.0%	0.0%	0.0%
≤ 5	0.1%	0.0%	0.0%	0.0%
≤ 0	0.0%	0.0%	0.0%	0.0%

* Calculated from monthly weather data (Dec, Jan, Feb) for Jan 1981-Feb 2011 (National Climatic Data Center).

Daily Sub-Freezing Extreme Low Temperatures in Demand Centers Outside Texas*				
Percent Probability of Occurrence on Any Given Winter Day (Dec, Jan, Feb - all equal)				
Temperature Milestone (°F)	Atlanta GA	Chicago IL	New York NY	Washington DC
≤ 32	32.3%	86.3%	57.3%	56.9%
≤ 30	25.1%	81.7%	48.2%	45.9%
≤ 25	12.1%	66.3%	28.6%	22.7%
≤ 20	5.3%	49.3%	14.6%	9.1%
≤ 15	2.2%	34.1%	6.4%	3.5%
≤ 10	0.9%	21.8%	2.3%	1.2%
≤ 5	0.4%	13.1%	0.6%	0.4%
≤ 0	0.1%	7.2%	0.1%	0.1%

* Calculated from monthly weather data (Dec, Jan, Feb) for Jan 1981-Feb 2011 (National Climatic Data Center).

Daily Heating-Degree Days (HDDs) in ERCOT Weather Zones*				
Probability of Occurrence on Any Given Winter Day (Dec, Jan, Feb - all equal)				
Cumulative Percentile	North Central	South Central	Coast	South
5	4	3	3	2
10	6	4	4	3
25	12	8	8	5
30	13	9	9	6
35	14	10	10	7
40	16	11	11	8
45	17	12	12	8
50	18	13	13	9
55	19	14	14	10
60	20	15	15	11
65	22	16	16	12
70	23	17	17	13
75	24	19	18	15
80	26	20	20	16
85	28	22	22	18
90	30	25	24	21
95	34	29	28	25
99	41	36	35	33
99.5	43	39	38	36
99.8	46	43	41	39

* Calculated from monthly weather data (Dec, Jan, Feb) for Jan 1981-Feb 2011 (National Climatic Data Center).

Daily Heating-Degree Days (HDDs) in Demand Centers Outside Texas*				
Probability of Occurrence on Any Given Winter Day (Dec, Jan, Feb - all equal)				
Cumulative Percentile	Atlanta GA	Chicago IL	New York NY	Washington DC
5	4	21	14	12
10	7	25	17	15
25	13	31	23	20
30	15	32	24	22
35	16	34	25	23
40	17	35	27	24
45	18	36	28	25
50	20	38	29	26
55	21	39	30	28
60	22	41	31	29
65	23	42	32	30
70	24	44	34	31
75	26	46	35	33
80	27	48	37	34
85	29	50	38	36
90	32	54	41	38
95	35	58	44	42
99	41	68	51	48
99.5	44	72	54	50
99.8	47	76	57	53

* Calculated from monthly weather data (Dec, Jan, Feb) for Jan 1981-Feb 2011 (National Climatic Data Center).

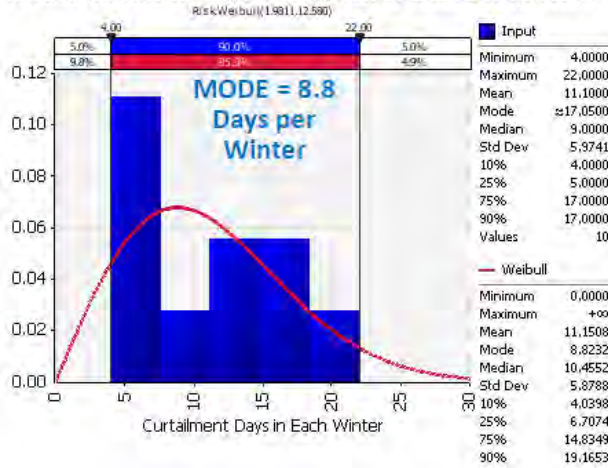
Climate Normal Heating-Degree Days (HDDs)*								
	North Central	South Central	Coast	South	North	West	Far West	East
Jan	557	413	366	242	715	624	659	578
Feb	394	265	241	127	535	461	464	406
Mar	201	89	73	11	339	270	292	253
Apr	12	0	0	0	79	37	48	43
May	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0
Oct	3	0	0	0	51	26	43	16
Nov	230	119	90	21	370	311	363	280
Dec	528	379	327	203	692	613	638	521
TOTAL	1925	1265	1097	604	2781	2342	2507	2097
WINTER MONTH (Avg of Jan, Feb, Dec)	493	352	311	191	647	566	587	502

* Calculated from monthly weather data for 1981-2010 (National Climatic Data Center).

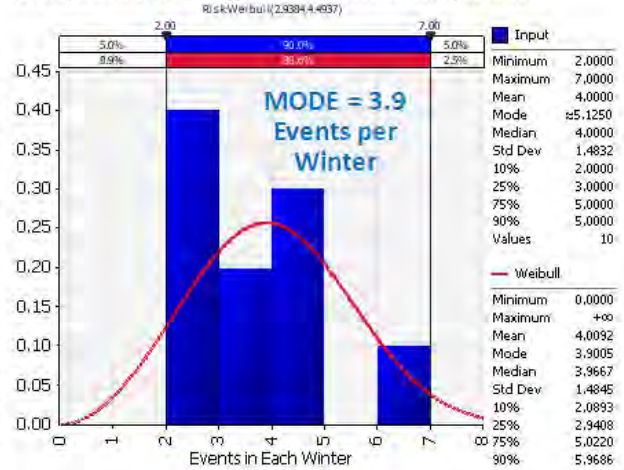
Climate Normal Heating-Degree Days (HDDs)*				
	Atlanta GA	Washington DC	New York NY	Chicago IL
Jan	673	897	988	1281
Feb	500	728	831	1044
Mar	330	566	708	841
Apr	91	247	371	484
May	0	22	87	182
Jun	0	0	0	2
Jul	0	0	0	0
Aug	0	0	0	0
Sep	0	0	2	53
Oct	67	171	215	387
Nov	329	465	505	739
Dec	615	785	831	1157
TOTAL	2605	3881	4538	6170
WINTER MONTH (Avg of Jan, Feb, Dec)	596	803	883	1161

* Calculated from monthly weather data for 1981-2010 (National Climatic Data Center).

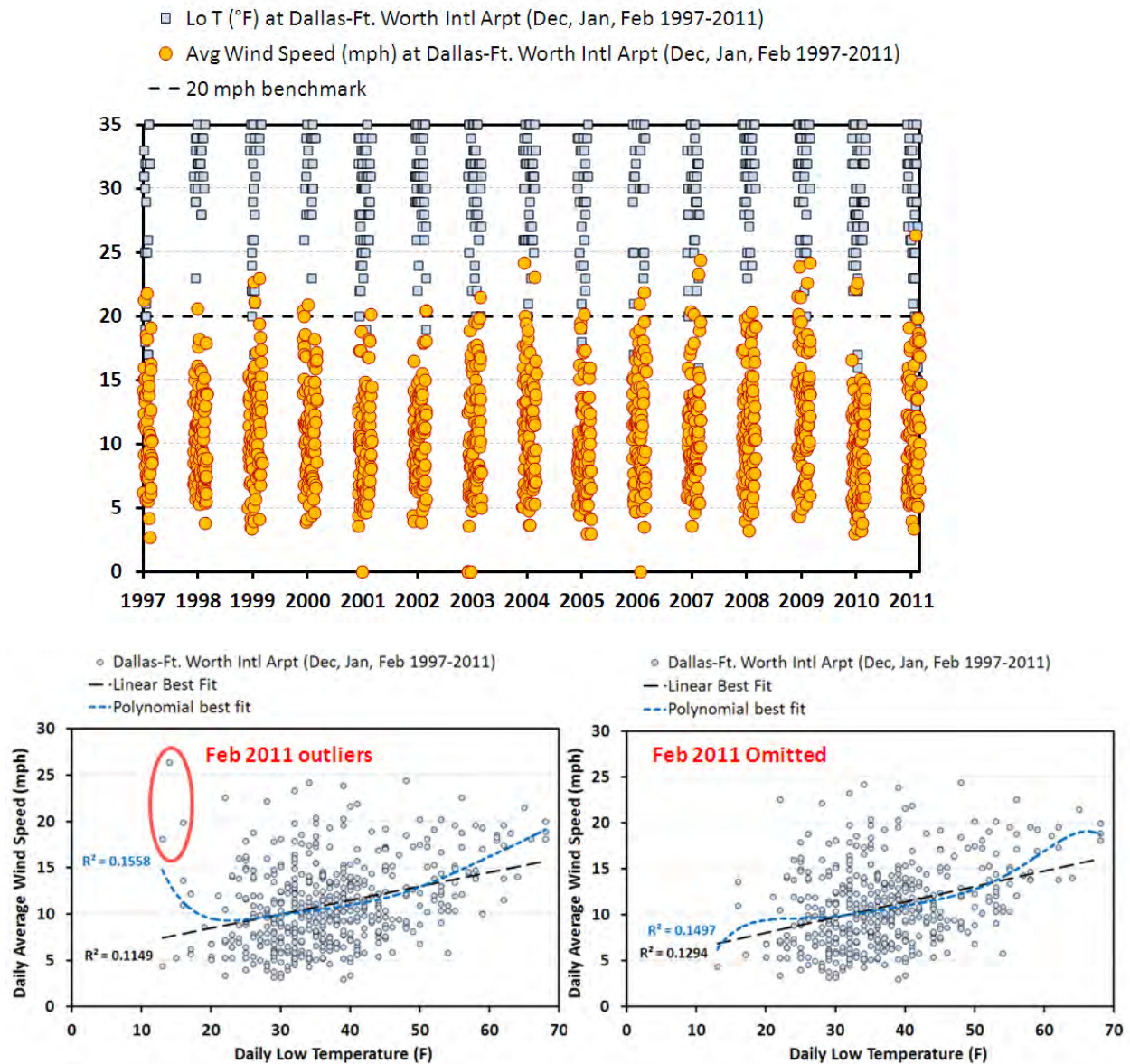
Fit Comparison for ERCOT-Logged Freezing-Weather Curtailment Days, 2002-2...



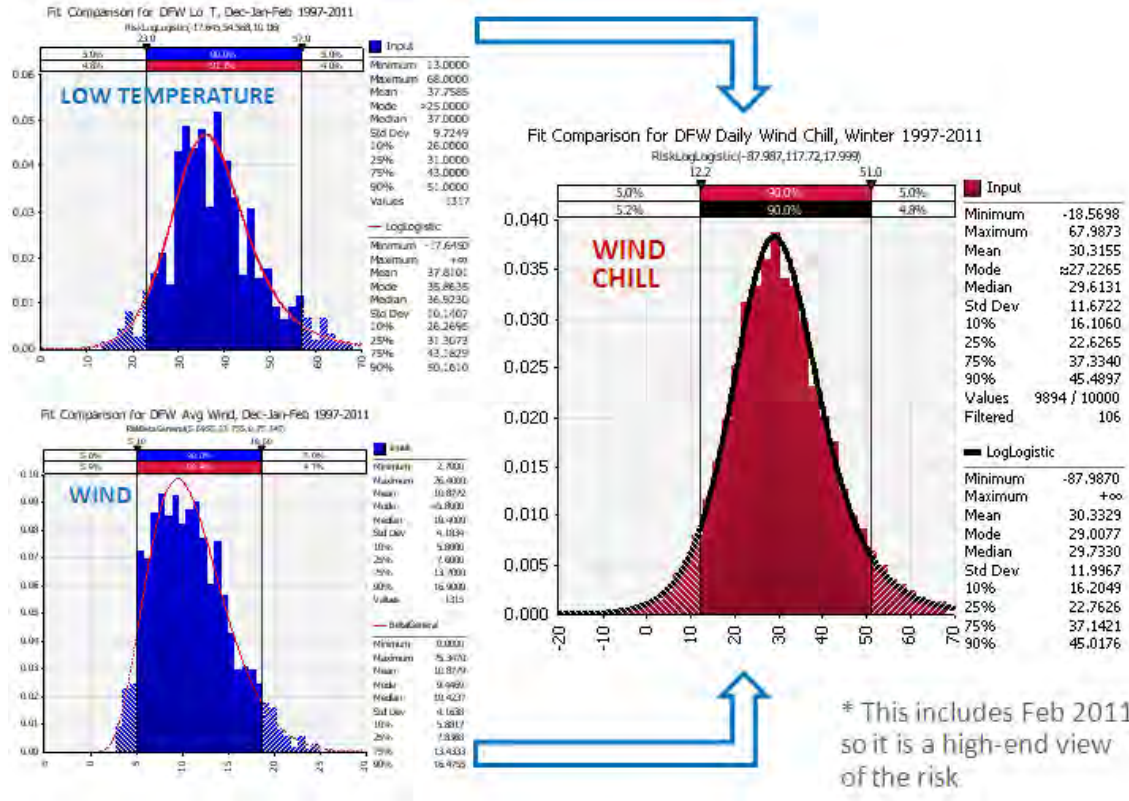
Fit Comparison for ERCOT-Logged Freezing-Weather Events, 2002-2011



Combined Effects of Sub-Freezing Temperatures and Strong Winds. The following charts summarize analysis of the ERCOT North Central Weather Zone with regard to strong winds during extreme freezing events:



The February 2011 curtailment event in ERCOT was unusual with regard to occurrence of high winds at the same time as extreme low temperatures. Indeed, the February 2011 data can be regarded as outliers²⁴ from the larger trend which shows declining winds correlated with declining winter low temperatures. If Feb 2011 data are omitted, there is no statistical case for winds becoming stronger as temperature falls – indeed the opposite trend prevails. Even if the February 2011 wind data are included as a worst-case scenario, the convolved freeze-wind PDF implies a level of wind-chill risk which is no more important than the risk of sub-freezing physical temperatures in the range of 25-30° F.



- North Central (1997-2011*) as model for temperature-wind risk
- “% Prob” is probability for occurrence on any given winter day
- Chance for average wind ≥ 20 mph is 2.6% (i.e., 97.4% likely to be calmer)
- Chance for wind chill ≤ 20° F is 16.8% (i.e., 83.2% likely to be warmer)
- Chance for ≤ 20° F wind chill is same as for ≤ 29° F physical (16.5%)
- Equally tangible threat is 25-30° F physical temperature

Daily Lo T (°F)	% Prob	Daily Avg Wind (mph)	% Prob	Daily Wind Chill (°F)	% Prob
< 32	27.6%	< 25	99.7%	< 32	59.1%
< 30	20.0%	< 20	97.4%	< 30	52.1%
< 25	7.4%	< 15	84.7%	< 25	32.2%
< 20	2.2%	< 10	46.2%	< 20	16.8%
< 15	0.5%	< 5	5.2%	< 15	8.0%
< 10	0.1%	< 1	0.0%	< 10	3.4%
< 5	0.0%			< 5	1.3%
< 0	0.0%			< 0	0.5%

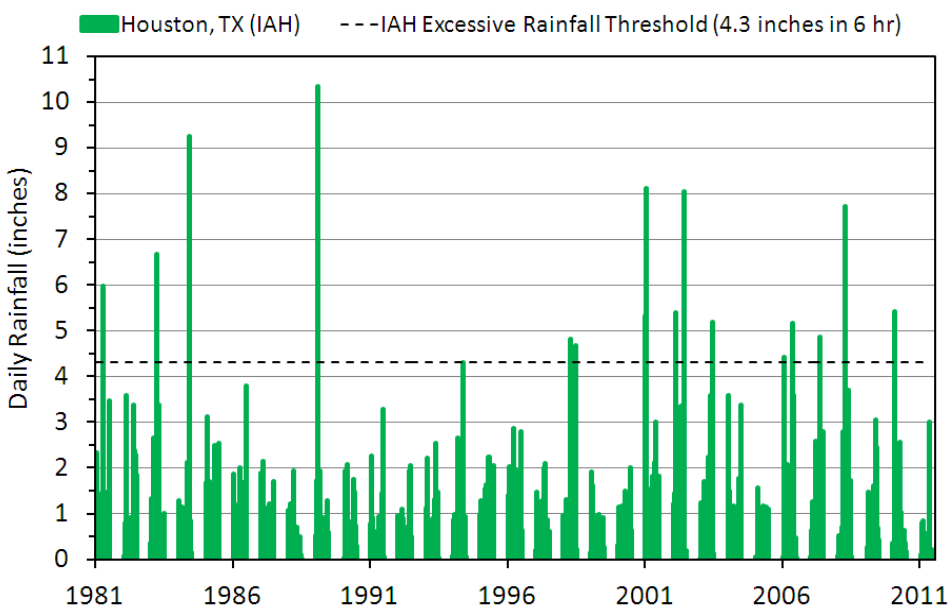
25-30° F physical is equally tangible to 20° F wind chill

* This includes Feb 2011 so it is a high-end view of the risk

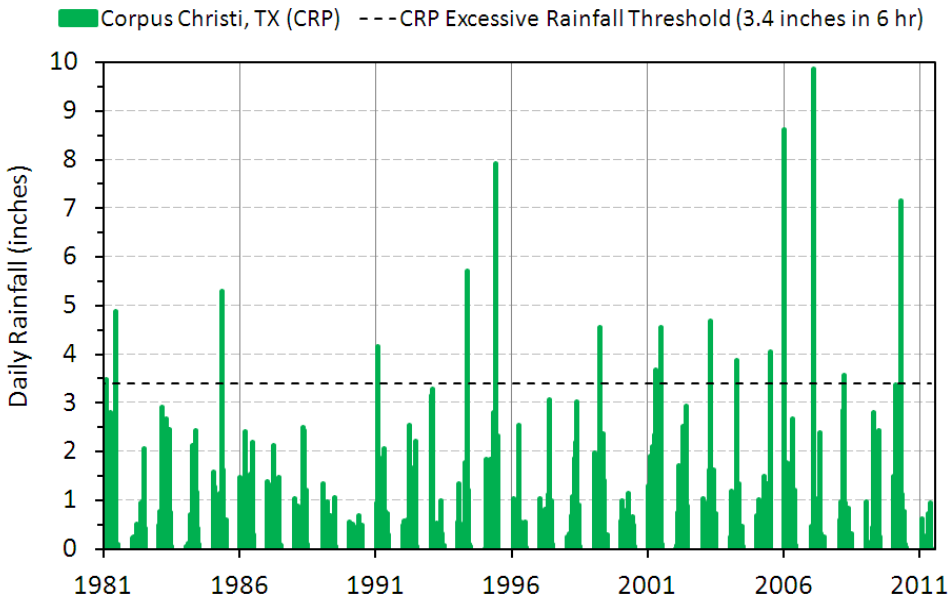
Tropical Cyclones.

NHC records were analyzed to compile tropical cyclone occurrences in the Gulf of Mexico (GOM) during the years of 1981-2011. Those data were used in the probabilistic risk analyses as described in 5.1 Summary of Approach. Focus was limited to correlation of tropical cyclones activity with shut-in of GOM gas production as a link to understanding gas supply curtailments. Coastal flooding, and its possible impacts on onshore gas-processing facilities, was considered initially but excluded from quantitative analysis. Nonetheless, data were compiled for flooding events in Houston and Corpus Christi to document the frequency of occurrence of flooding as a prospective causal event. In both charts, all data bars which stand taller than the excessive-rainfall threshold (horizontal dashed line) represent flood events. The following charts show timelines for flooding events at Houston and Corpus Christi, respectively. During the 2002-2011 period covered by the ERCOT Operator Logs, there were at least 8 potential flooding events at Houston and 7 at Corpus Christi although the Logs did not identify flooding as contributing to a gas curtailment.

**Daily Precipitation During Hurricane Season (Jun-Nov),
1981-2011**



Daily Precipitation During Hurricane Season (Jun-Nov), 1981-2011



APPENDIX C – STATISTICAL DETAILS

Risk frequencies were approached for two different frameworks:

- **Event Risk.** The probability that a given causative agent will occur within any given winter (freezing weather), hurricane season (tropical cyclones) or year (pipeline outages).
- **Power-Outage Risk.** The probability that a given level of loss (MW or percentage of total generation portfolio) will occur for ERCOT power generation within any given winter, hurricane season or year in response to causative events.

Event Risk for freezing weather or for tropical cyclones can be done independently through statistical analysis of historical weather data. Because the weather data sets for 1981-2011 are continuous and complete, the derived statistics can be considered robust and confidence in their application to risk prediction is considered strong. The situation for pipeline risks is much less assured because detailed records for gas curtailments attributable to pipeline problems are neither complete nor continuous. So for pipeline events, predicted frequencies of event risk will necessarily carry larger uncertainties.

Power-Outage Risk depends crucially on information about how causative agents impact power generation. Specifically, each event must be documented with regard to how much gas flow (MMBtu/d) or power generation (MW) was lost in the event. As found in the current study, meaningful analyses of Power-Outage Risk are limited by relatively few and incomplete records for the amounts of gas or power lost in any individual event. Because power-loss reports were more numerous than gas-loss reports (Table 3), direct analysis of event frequency was possible in terms of power loss (MW) for freezing-weather events. For pipeline outages, a nearly direct analysis was possible except that, because most impact data were reported as gas losses (MMBtu/d), an additional step was necessary to convert gas losses to power losses (MW) based on characteristic of ERCOT gas-fired generators. For tropical cyclones, Power-Outage Risk was approached indirectly in a three-step process: (1) Determine frequency of tropical cyclone events that curtail Gulf of Mexico (GOM) gas production; (2) Determine the proportion of ERCOT gas needs represented by the lost GOM production; (3) Translate the gas loss into equivalent loss of gas-fired power generation.

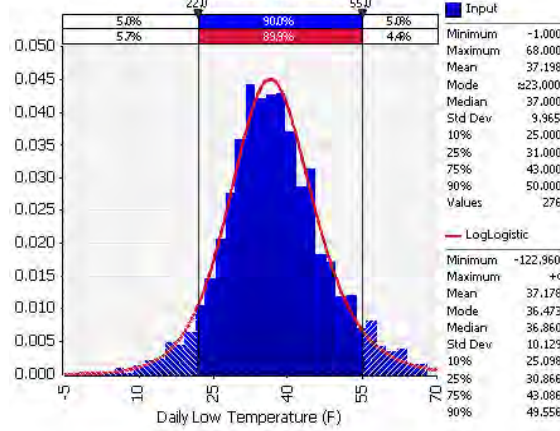
Clearly, Power-Outage Risk should be the metric of most obvious interest to ERCOT although Event Risk also is useful in understanding the relative threats posed by different causative agents. Event Risks become especially important in appreciating the impacts of freezing weather when such events occur both in Texas as well as in other gas-demand regions.

The following figure illustrates the effects of sample size on the robustness of statistics derived by fitting distribution functions to real data. In the left-hand chart (Lo T at Dallas-Ft. Worth), where the analysis is supported by 2,766 data points, the spread around the mode (most likely) value is 28%. In the right-hand chart (MW of gas-fired generation curtailed during freezing-weather events) the same measure of spread is 124% where the analysis rests on only 32 data points.

Lo-T Relative Modal Spread = (Std Dev / Mode) = 10.1 / 36.5 = 27.7%

MW Relative Modal Spread = 943.7 / 758,2 = 124.5%

Fit Comparison for NORTH CENTRAL Winter Daily Lo T, Dec-Jan-Feb 1981-2011
RiskLogLogistic(-122.96,159.82,28.74)

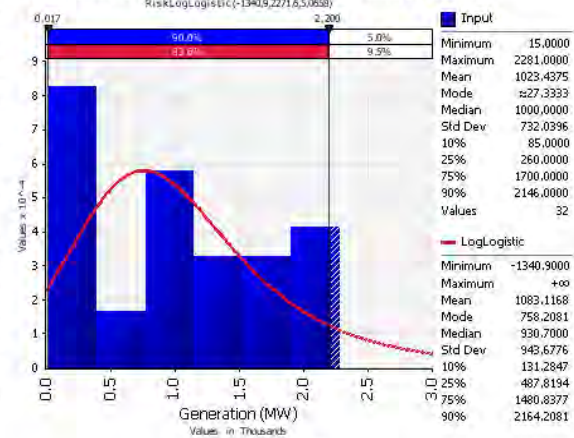


Log-Logistic PDF

Data Points: 2,766

Modal Spread: 28%

Fit Comparison for ERCOT Gas-Fired Gen (MW) Curtailed by Freeze
RiskLogLogistic(-1340.9,2271.6,5.0638)



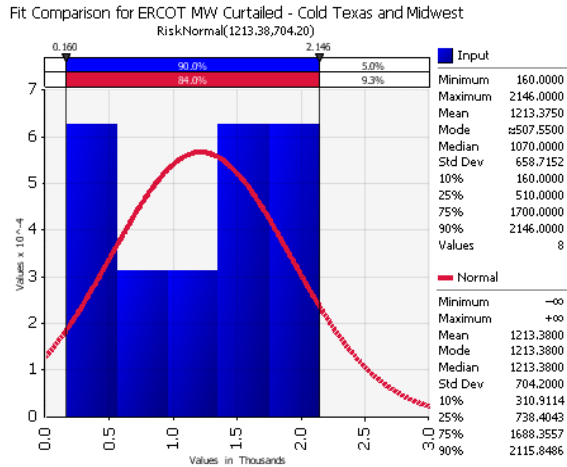
Log-Logistic PDF

Data Points: 32

Modal Spread: 124%

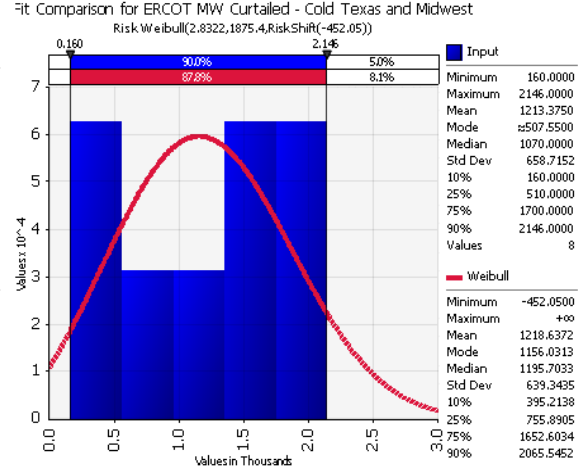
The important message is that event data sets with only a few members (examples) carry larger degrees of uncertainty in the analytical results. Attempts to further differentiate (sub-divide) small data sets in search of sub-scenarios inevitably inflate the uncertainties relative to analysis of “undifferentiated” data sets for a given curtailment cause.

As a further example of statistical sensitivities related to sample size, the following figure shows the effect of different PDF functions when applied to the same small data set. The choice of PDF is associated with a difference of about 4% in the key attributes of mode, modal spread and 90th percentile values. In the current study, such variations among the top three PDFs for each data set (as judged from Anderson-Darling goodness of fit) were used to estimate errors in the results derived from probabilistic analyses.



Normal PDF

Data Points: 8
 Mode (Most Likely) Value: 1,213 MW
 Modal Spread: 58%
 90th Percentile: 2,116 MW



Weibull PDF

Data Points: 8
 Mode (Most Likely) Value: 1,156 MW
 Modal Spread: 55%
 90th Percentile: 2,065 MW

APPENDIX D – TEXAS RAILROAD COMMISSION CURTAILMENT PLAN

OIL AND GAS DOCKET GAS UTILITIES DIVISION

NO. 20-62,505 DOCKET NO. 489³⁶

ORDER

RELATING TO THE APPROVAL BY THE COMMISSION OF CURTAILMENT PROGRAMS FOR NATURAL GAS TRANSPORTED AND SOLD WITHIN THE STATE OF TEXAS

After due notice the Railroad Commission of Texas on the 30th day of November, 1972, heard testimony and requested written curtailment priorities from representatives of investor owned and municipal gas utilities companies, private industry consumers and others responsible for directing available natural gas supplies to the consumers of natural gas in the State of Texas.

WHEREAS, pursuant to the authority granted to the Railroad Commission of Texas in Article 6050 to 6066, inclusive, R.C.S., as amended; and

WHEREAS, the Commission has determined the need for a curtailment program to assure effective control of the flow of natural gas to the proper destinations to avoid suffering and hardship of domestic consumers; and

WHEREAS, the Commission has determined a need to make natural gas available to all gas consumers on a reasonable but limited basis during times of needed curtailment to the end that the public will be best served; and

WHEREAS, the Commission has determined that the transportation delivery and/or sale of natural gas in the State of Texas for any purpose other than human need consumption will be curtailed to whatever extent and for whatever periods the Commission may find necessary for the primary benefit of human needs customers (domestic and commercial consumption) and such small industries as cannot practically be curtailed without curtailing human needs.

IT IS THEREFORE, ORDERED BY THE RAILROAD COMMISSION OF TEXAS that the following rules relating to the approval by the Commission of curtailment programs for gas transported and sold within the State of Texas shall apply to all parties responsible for directing available and future natural gas supplies to the consumers of natural gas in the State of Texas.

RULE 1.

Every natural gas utility, as that term is defined in Article 6050, R.C.S. of Texas, as amended, intrastate operations only, shall file with the Railroad Commission on or before Feb. 12, 1973, its curtailment program. The Commission may approve the program without a hearing; set the matter for a public hearing on its own motion or on the motion of any affected customer of said utility.

The curtailment program to be filed shall include, in verified form, the following information:

A. Volume of gas reserves attached to its system together with a brief description of each separate source of gas reserves setting forth the following:

1. the name of the supplier,
2. the term of each contract in years, and the years remaining on said contract,
3. the volume of recoverable reserve contracted for, and
4. rated deliverability of such reserves in MCF.

³⁶ TRRC Gas Curtailment Plan of 1973. Oil and Gas Docket, Gas Utilities Division, No. 20-62, 505, Docket No. 489, January 5, 1973. <http://www.rrc.state.tx.us/meetings/dockets/docket489.php>. Incorporated into Texas Administrative Code, Title 16, Part 1, Chapter 7, Subchapter C, Rule §7.305.

- B. Capacity and location of underground storage, if any, attached to its system with a statement of whether the company's storage balance is above or below its desired level for this time, and, if below, what plans has the company made to restore the balance.
- C. Peak day and average daily deliverability on an annual basis of its wells, gas plants and underground storage attached to its system.
- D. Peak day capacity of its system.
- E. Forecast of additions to reserves for each of the next two succeeding years.
- F. Location and size of the line pipes, compressor stations, operating maximum line pressures, and a map showing delivery points along the system.
- G. Disposition of all gas entering its system, with names of all customers other than residential customers and volumes delivered to each during the past calendar year. Identify those customers using 3,000 MCF gas per day, or more, which are under a service contract, and if such contract includes an "Interruptible Service" clause, and if so, attach a reproduced copy of the relevant provisions of such contract.
- H. Steps taken in past years, being taken at the present, and to be taken to alleviate curtailments.

RULE 2.

Until such time as the Commission has specifically approved a utilities curtailment program, the following priorities in descending order shall be observed:

- A. Deliveries for residences, hospitals, schools, churches and other human needs customers.
- B. Deliveries of gas to small industrials and regular commercial loads (defined as those customers using less than 3,000 MCF per day) and delivery of gas for use as pilot lights or in accessory or auxiliary equipment essential to avoid serious damage to industrial plants.
- C. Large users of gas for fuel or as a raw material where an alternate cannot be used and operation and plant production would be curtailed or shut down completely when gas is curtailed.
- D. Large users of gas for boiler fuel or other fuel users where alternate fuels can be used. This category is not to be determined by whether or not a user has actually installed alternate fuel facilities, but whether or not an alternate fuel "could" be used.
- E. Interruptible sales made subject to interruption or curtailment at Seller's sole discretion under contracts or tariffs which provide in effect for the sale of such gas as Seller may be agreeable to selling and Buyer may be agreeable to buying from time to time.

RULE 3.

Each gas utility that has obtained Commission approval of a curtailment program shall conduct operations in compliance with such program.

So long as any gas utility which has obtained Commission approval of a curtailment program continues to curtail deliveries to its customers, except as provided by contract or those customers included in Part E of Rule 2 above, it (a) shall file on or before April 1 of each year, under oath, the information called for in Rule 1, for the preceeding year, and (b) shall not, without Commission approval, make sales of gas to any new customers or increase volumes sold to existing customers, except those new or existing customers defined in Parts A & B of Rule 2 above.

IT IS FURTHER ORDERED that this cause be held open for such other and further orders as may be deemed necessary.

ENTERED AT AUSTIN, TEXAS, this 5th day of January, 1973.

APPENDIX E – LIQUIDITY IN TEXAS NATURAL GAS MARKET

Natural gas-fired electric generators have exposure to risk arising from lack of liquidity in the natural gas markets. Natural gas supply contracts entered into by gas-fired electric generators that rely upon short-term and flexible obligations have a greater exposure to changes in market liquidity. This liquidity risk can be especially exacerbated during times of stress for the natural gas markets such as severe weather or infrastructure disruptions. Electric generators that rely upon longer term firm supply transactions have exposure to liquidity risk when supply disruptions occur but overall the likelihood for disruption and exposure to liquidity risk is generally lower for term supply agreements when compared to spot supply agreements. Any limitations in the liquidity of the natural gas market could pose the risk of gas supply curtailment to electric generators in its region – regardless of contract term. This section examines the liquidity of the natural gas market in Texas to better understand the risks of gas supply curtailment to electric generators within ERCOT’s service region.

Texas is the largest producer and consumer of natural gas and also has the distinction of having the most number of miles of natural gas pipelines in the U.S. As a result, Texas enjoys a very robust natural gas market with multiple participants and well developed infrastructure that includes natural gas production facilities, natural gas processing facilities, interstate and intrastate natural gas pipelines and natural gas storage facilities.

The study examines the liquidity within Texas by looking at the following indicators within the natural gas market:

- A. Regulatory framework for pipelines
- B. Standardization of bi-lateral transactions via NAESB contracts
- C. Evolution to the use of short term gas supply contracts
- D. FERC price reporting requirements
- E. Overview of Texas pricing locations and market liquidity
- F. Recent history of daily spot market liquidity during unique events

A. Natural Gas Pipeline Regulatory Framework

Natural gas market transportation in Texas is either regulated by the Federal Energy Regulatory Commission (FERC), for pipelines involved in interstate commerce, or the Railroad Commission of Texas (TRRC), for pipelines serving intrastate markets. These regulatory bodies create a framework of open access to transportation capacity within the Texas market. Each regulates pipeline transportation capacity using different structures, with the FERC being viewed by industry as enforcing more detailed open access and tariff regulations. The extensive pipeline network and associated regulatory oversight creates the foundation within Texas for transparent and liquid natural gas markets.

Interstate Regulation

The FERC regulates all services provided by interstate pipelines through the implementation of the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978. FERC

requires that interstate pipelines provide non-discriminatory open access to pipeline services. These terms of conditions for the pipeline services must be delineated in the pipeline's FERC Gas Tariff or Statement of Operating Conditions (SOC). A natural gas pipeline must consistently implement its tariff in compliance with the regulations. The purpose of this section is to review the key components of the tariff and SOC.

The large FERC regulated pipelines serving ERCOT power generators include Texas Eastern Transmission, CenterPoint Energy, El Paso Natural Gas, Natural Gas Pipeline Company of America, Tennessee Gas Pipeline, and Transcontinental Pipeline.

The FERC's open access requirements serve to enhance shippers' access to physical pipeline capacity. Primarily, a pipeline must provide service on a not unduly discriminatory basis to any prospective shipper willing to pay the maximum rate specified in a pipeline's tariff. Furthermore, pipelines offering firm service are required by the FERC to also offer interruptible service, which is of particular significance to power generators that require access to intermittent gas supplies when serving peak day demand.

In addition to providing shippers open-access to interstate pipelines, FERC regulations also provide transparency within the interstate pipeline market. FERC regulations ensure that shippers are fully aware of the transportation services offered by interstate pipelines because an interstate pipeline may only provide the services which are approved by the FERC and which are part of its tariff. Furthermore, services offered on interstate pipeline tariffs must incorporate North American Energy Standards Board (NAESB) standards helping to facilitate uniformity of terms and services.

The FERC has promulgated various significant orders which have produced the pipeline services that exist today. Through Order 436, Order 636, and Order 637, the FERC fundamentally changed the services that pipelines provide to customers. The principles established in these key Orders continue to be reflected in the FERC's orders today as they apply to the natural gas industry.

Order 436. With the issuance of Order 436, FERC mandated open access, nondiscriminatory transportation, i.e., that pipelines must transport gas on a first-come, first-served basis for any local distribution company or shipper requesting service, to the extent that capacity is available. The implementation of this order permitted gas users to buy gas directly from gas producers and marketers and to transport the gas on an interstate pipeline. Pipelines were required to design rates that rationed capacity during peak periods and maximized throughput during off-peak periods.

Order 636. In this order, FERC required pipelines to unbundle or separate sales and transportation services at upstream points on the pipeline systems as near to production as possible. Pipelines were required to offer various transportation services such as "no-notice" service, unbundled storage service and interruptible transportation service. Pipelines were directed to design rates on the Straight-Fixed Variable method³⁷.

³⁷ Under straight fixed variable rate design, all fixed costs associated with transportation service (including return on equity, taxes, and depreciation) are recovered through fixed reservation charges.

Significantly, FERC modified the existing capacity brokering programs, instead creating a capacity release model where parties that held excess transportation capacity could 'release' this capacity to other parties interested in acquiring it. The order also addressed the appropriate allocation of pipeline capacity.

Order 637. Order 637 revised numerous service features by permitting term-differentiated rates; temporarily waving the price ceiling on short-term released capacity; revised regulations addressing nominations scheduling, capacity segmentation, penalty charges and right of first refusal.

Intrastate Regulation

The TRRC is the primary regulator of intrastate natural gas pipelines. The TRRC is charged with implementing and enforcing Standards of Conduct. The mandate to ensure reliability of service was first introduced with the Cox Act of 1920 which prohibited discriminating against shippers in services or charges. The TRRC defines the standards of conduct governing the provision of gas transportation services in order to prevent discrimination.

As background, the larger TRCC-regulated pipelines serving ERCOT power generators include Atmos Energy Corporation, Enterprise Products Partners, L.P., Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P.:

The TRRC rules provide that any transporter that provides transportation services for any shipper shall:

- Apply any tariff or contract provision for transportation services which provides for discretion in the application of the provision in a similar manner to similarly-situated shippers;
- Enforce any tariff or contract provision for transportation services if there is no discretion stated in the tariff or contract in the application of the provision in a similar manner or similarly-situated shippers
- Not give any shipper preference in the provision of transportation services over any other similarly-situated shippers;
- Process requests for transportation services from any shipper in a similar manner and within a similar period of time as it does for any other similarly-situated shipper; and maintain its books of account in such a fashion that transportation services provided to an affiliate can be identified and segregated

The TRRC derives its authority to regulate the gathering and transportation of natural gas by intrastate entities from three primary statutes: The Cox Act of 1920, the Common Purchaser Act of 1930, and the Gas Utility Regulatory Act of 1983.

The Cox Act. The Cox Act of 1920 resulted from the inability of North Texas cities to secure adequate gas supplies during the winters of 1919 and 1920. The Act applies to any gas utility which is defined as any "person who owns, manages, operates, leases, or controls in this state property or equipment or a pipeline, plant, facility, franchise, license, or permit for

a business". Under the Cox Act the TRRC is authorized to regulate rates for sale and transport of gas and to set rules for control and supervision of pipelines. Gas Utilities, as defined by the Cox Act are prohibited from engaging in discrimination in services and charges. Specifically:

- *A pipeline gas utility may not discriminate in favor of or against any person or place in: apportioning the supply of natural gas; or charging for natural gas; or*
- *directly or indirectly charge, demand, collect, or receive from anyone a greater or lesser compensation for a service provided than the compensation charged, demanded, or received from another for a similar and contemporaneous service.*

Common Purchaser Act. The Common Purchaser Act was passed in reaction to huge discoveries of oil in East Texas in 1930, plummeting prices, control of pipelines by big producers and civil unrest and martial law. The act defines Common Purchasers as:

- *"every person, gas pipeline company, or gas purchaser that claims or exercises the right to carry or transport natural gas by pipeline or pipelines for hire, compensation, or otherwise within the limits of this state or that engages in the business of purchasing or taking natural gas, residue gas, or casinghead gas."*

The TRRC exercises authority under the Act and is authorized to enforce compliance and make rules "necessary to prevent discrimination, order pipeline extensions and ratable purchases that will prevent discrimination and issue show cause orders to common purchasers.

Gas Utility Regulatory Act. Originally enacted as part of the Public Utility Regulatory Act it was separated in 1983. This Act defines a Gas Utility as a person that owns or operates for compensation in Texas facilities to transmit or distribute natural gas for sale or resale in a manner not regulated by the FERC. The Act provides that gas utilities may not establish or maintain "an unreasonable difference" concerning rates or services between places or customer classes". It also provides that gas utilities may not "engage in a practice that tends to restrict or impair" competition.

Oil and Gas Docket – Gas Utilities Division No. 20-62,505 Docket No. 489. In 1972 the TRRC created regulations that require a curtailment plan for natural gas utilities with a defined sequence for gas delivery curtailments. Natural gas pipelines can theoretically fall outside these regulations if they are not classified as a utility. As a practical matter most pipelines are classified as utilities and must adhere to these regulations and curtailment programs.

Rule 1 of the regulations requires that every natural gas utility, as that term is defined in Article 6050, R.C.S. of Texas, as amended, intrastate operations only, will file with the TRRC its curtailment program that is subject to review and approval by the TRRC.

Rule 2 of the regulations define the following priorities of service and curtailment order. The following is a listing of priorities in descending order:

- A. *Deliveries for residences, hospitals, schools, churches and other human needs customers.*
- B. *Deliveries of gas to small industrials and regular commercial loads (defined as those customers using less than 3,000 MCF per day) and delivery of gas for use as pilot lights or in accessory or auxiliary equipment essential to avoid serious damage to industrial plants.*
- C. *Large users of gas for fuel or as a raw material where an alternate cannot be used and operation and plant production would be curtailed or shut down completely when gas is curtailed.*
- D. *Large users of gas for boiler fuel or other fuel users where alternate fuels can be used. This category is not to be determined by whether or not a user has actually installed alternate fuel facilities, but whether or not an alternate fuel "could" be used.*
- E. *Interruptible sales made subject to interruption or curtailment at Seller's sole discretion under contracts or tariffs which provide in effect for the sale of such gas as Seller may be agreeable to selling and Buyer may be agreeable to buying from time to time.*

As discussed above, incremental regulatory developments over the course of many decades have contributed to a regulatory regime that provides oversight and facilitates open access and consistent practices in acquiring transportation capacity on natural gas pipelines operating within Texas. Electric generators (and other consumers of natural gas) benefit from the mechanisms that are in place to facilitate the efficient functioning of the natural gas transportation capacity market within Texas.

B. Standardization of Bi-lateral Transactions via NAESB

The NAESB is a group comprised of energy industry participants that aims to develop best business practices for the natural gas and electric markets. Originally founded in 1994 as the Gas Industry Standards Board (GISB), the organization expanded in January 2002 to cover, in addition to the retail natural gas market, issues pertaining to wholesale natural gas, wholesale electric, and retail electric markets. NAESB standards are widely recognized by government agencies, as the organization has public-private partnerships with the FERC, Department of Energy, Department of Transportation, state commissions, the Mexican government regulatory agency - the Comision Reguladora de Energia (CRE), and the Canadian regulatory agency - the National Energy Board. Some regulatory agencies have chosen to adopt NAESB standards. For example, the FERC requires natural gas pipelines under its jurisdiction to incorporate wholesale NAESB standards into their tariffs.

The NAESB has been highly influential by standardizing a contract for wholesale natural gas transactions. This standardized contract has served to facilitate the sale and purchase of natural gas in a transparent and efficient manner, which therefore enhances market liquidity. NAESB wholesale natural gas contracts follow a four part structure: (1) the base contract, (2) general terms and conditions, (3) a transaction confirmation, and (4) a special provisions addendum. The general terms and conditions of each contract allow for continual bi-lateral agreements to be reached, while special provisions can be made for individual agreements as necessary.

The NAESB Base Contract for Sale and Purchase of Natural Gas has materially contributed to the ease of sale and purchase transactions in the natural gas industry. Using the NAESB contract as a blanket contract allows counterparties to enter into transactions with each other with short notice without the delays associated with negotiating legal and commercial terms on a bilateral basis for each transaction.

Use of a NAESB agreement is not required by natural gas market participants and, specifically, electric generators. However the use of a NAESB agreement does allow electric generators to create a robust group of gas suppliers to acquire natural gas fuel from on a short and long term basis. While the NAESB contract does not create or eliminate liquidity, it does facilitate the ability to quickly transact with multiple counterparties on a bilateral and exchange basis to meet supply needs during unique market events.

C. Evolution to the Use of Short-Term Gas Supply Contracts

The natural gas market has evolved from one of regulated supply and prices to a deregulated market for prices and a much more robust, and market sensitive, market for transportation services. Prior to FERC Order 436, the majority of gas sales / supply agreements in interstate commerce were multi-year commitments between the pipeline and buyer. This was due, in part, to the lack of local supply alternatives for buyers and the requirements that gas sales in interstate commerce be subject to price regulations under the Natural Gas Act. Gas sales / purchases in intrastate commerce in Texas were subject to alternative regulations. However contracting practices in the Texas intrastate market commonly mirrored those in interstate commerce and tended to be multi-year sales / purchase agreements.

With the deregulation of the interstate market, for both price and pipeline open access, the short-term market began to emerge as a vehicle to manage short-term fluctuations in supply and demand. The short-term market has been commonly called the spot market. Contract terms for spot supply typically range from one day to one month. Currently prices for natural gas are gathered by FERC and third parties and reported in various publications / reports. For physical gas delivery, the prices are commonly reported for day-ahead transactions and monthly transactions. We review the market reporting requirements in more detail in the following section.

The reporting activity has created substantial transparency and liquidity in the short-term or spot U.S. natural gas market. This in turn has led to an increased confidence in liquidity and utilization of the spot market for buying and selling natural gas. This is especially beneficial for consumers such as electric generators who require flexibility in the daily amount of natural gas supply they source. Longer term transactions still remain but tend to be priced off of the spot market with minimal differentiation in pricing between spot transactions vs. longer term (multi-month to multi-year) transactions.

D. Understanding FERC's Price Reporting Requirements for Natural Gas Market Participants

FERC has implemented a regulatory framework to ensure that transparent market price indicators are available across the United States, including Texas. The FERC requires that any seller of natural gas that reports transactions to a publisher of natural gas prices follow minimum standards for reporting those prices. These requirements are established in FERC Regulation 18 CFR § 284.403 and the "Policy Statement On Natural Gas And Electric Price Indices", issued on July 24, 2003, in Docket No. PL03-3-000. The statement explains that firms reporting transactions to developers of index prices are required to adhere to the following guidelines:

- Create a clear code of conduct to be followed by its employees when buying or selling natural gas or electricity. A similar code of conduct is to be upheld when reporting these transactions to entities that report index prices.
- Trade data should be reported and its accuracy verified by a department of the company that is not involved in trading operations.
- Report all bi-lateral and arms-length transactions executed in the physical market between all non-affiliated firms at all trading locations. This does not include transactions executed in financial markets, such as hedges or swaps.
- Retain all data relevant to reported trades for a three year period and have the gathering and submission of this data independently audited at least once a year. The results of independent audits are to be made known to the entity to which index prices are reported.

These rules addressing price reporting were specifically designed to prevent manipulation of the natural gas market through any potential inaccurate price reporting behavior and to ensure greater transparency in natural gas prices. These rules create more oversight related to price reporting and contribute to greater price transparency in the natural gas market due to the requirement that market participants, which meet specific criteria, are obligated to report fixed price transactions to FERC. This in turn facilitates the reporting of transactions to industry publications which can be analyzed to understand overall market activity, number of transactions, and implications for market liquidity.

E. Overview of Texas Pricing Locations and Market Liquidity

Purchasers and sellers of natural gas benefit from a market that has multiple buyers and sellers which creates a transparent market. Buyer and seller participation can vary by location, "product" type (i.e. - term of the transaction such as daily spot or yearly term) and the type of service required (i.e. - firm or interruptible). Multiple participants, on both the purchase and sales side, create market liquidity which allows a more efficient means of price discovery. When the number of market participants is small, liquidity is reduced which makes it more difficult to buy/sell the natural gas services required. The lack of participation can be due to many different reasons such as buy/sale location, unavailability of natural gas due to supply disruptions or terms that are outside the norm.

The Texas natural gas market has historically enjoyed high liquidity with multiple market participants. Texas, the home of several supply basins and several major demand areas,

contains more than a dozen pricing points where natural gas is bought and sold. Figure E1 shows a map of these pricing points.

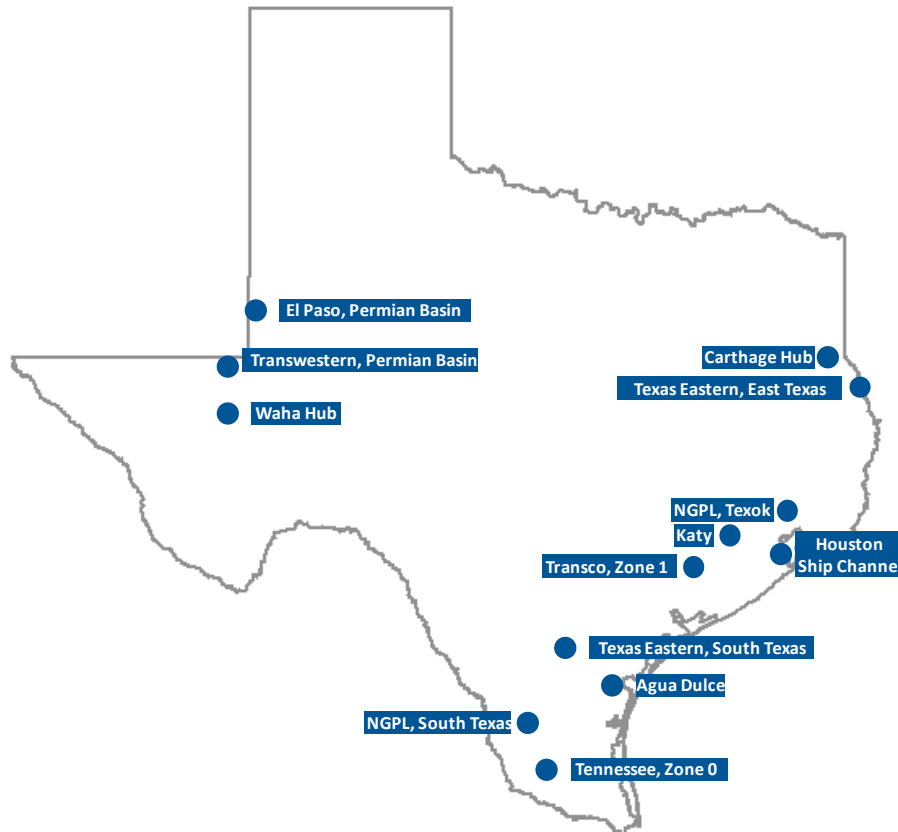


Figure E37: Texas Natural Gas Pricing Points.

Traded volumes of natural gas sold under fixed price arrangements recorded by Platts³⁸ provides a robust set of data points which may be used to assess the historical liquidity of the Texas market.

One approach to understand the comparative liquidity of a given pricing point for monthly purchase/sale transactions is reviewing the three-tier system applied by Platts since 2004 which groups trading points recorded in its monthly survey based on their monthly traded volumes or First of Month (FOM) volumes and the number of trades. Criteria for these tier rankings are summarized in Figure E2.

³⁸ Platts is a division of The McGraw-Hill Companies (NYSE-MHP), a global financial information and education company, whose other brands include Standard & Poor's, McGraw-Hill Education, J.D. Power & Associates, Aviation Week, and McGraw-Hill Construction.

	Volume Requirement (MMBtu/day)	Required Trades
Tier 1	100,000 and greater	10 and greater
Tier 2	25,000 to 99,999	5 and greater
Tier 3	less than 25,000	less than 5

Figure E38: Criteria for Platts Tier Rankings for Natural Gas Pricing Points.

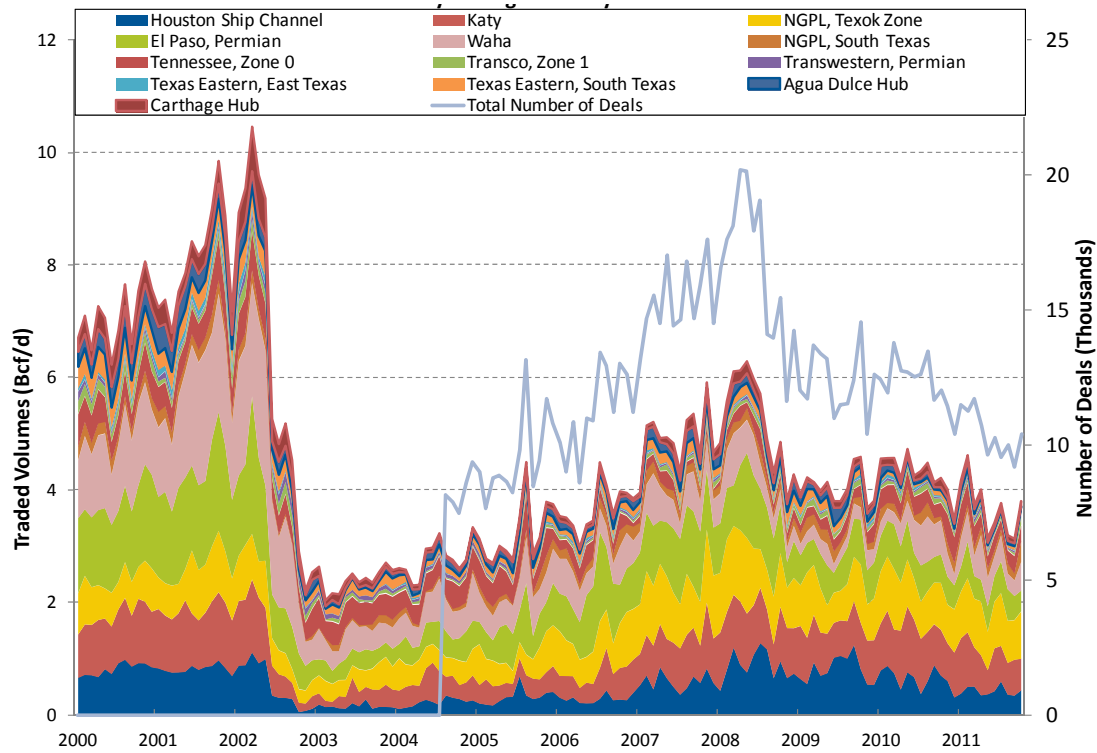
Figure E3 demonstrates the average tier assessed for each of the trading locations, for monthly transactions, within Texas during the 2004-2011 time period. As shown in this table, most Texas natural gas trading locations enjoy Tier 1 or 2 status with only a few locations assessed as being Tier 3. The tier rankings for monthly purchase/sale transactions provide an insight into the market liquidity in Texas natural gas market and the existence of multiple market participants.

Pricing Points	Historical Tier (Since 2004)
Agua Dulce Hub	FOM volumes not reported
Carthage Hub	FOM volumes not reported
El Paso, Permian	1
Houston Ship Channel	1
Katy	2
NGPL, South Texas	1/2
NGPL, Texok Zone	1
Tennessee, Zone 0	1
Transco, Zone 1	2
Transwestern, Permian	2/3
Texas Eastern, East Texas	2/3
Texas Eastern, South Texas	1
Waha	1

Figure E39: Historical Platts Tier Rankings for Texas Pricing Points

Review of daily spot market liquidity for Texas pricing locations

Understanding transaction activity, and therefore market liquidity, on a daily basis provides greater insight into a market’s liquidity for short-term purchases and risks that a buyer or seller faces in obtaining a transparent market price. Figure E4 provides an overview of daily traded volumes of natural gas in Texas as reported by *Gas Daily*, a Platts publication that is generally considered the leading source of reported natural gas price data. Daily traded volumes of natural gas fell across North America in the 2002-2003 time period following the exodus of trading and marketing firms that occurred as a result of the fallout of the collapse of Enron. Subsequently, changes were enacted by FERC in price-reporting practices/requirements that improved the transparency and accuracy of natural gas prices. As seen in Figure E4, the volumes traded in Texas have recovered and exhibited robust volumes averaging approximately 4.4 Bcf/d in the 2010-2011 period. As a point of reference, the total daily consumption of natural gas in Texas in 2010 was approximately 3 Bcf/d.



Source: Platts

Figure E40: Traded Volumes and Deals of Natural Gas Reported at Texas Pricing Points: Monthly Averages of Daily Volumes.

F. Recent History of Daily Spot Market Liquidity During Unique Events

With an understanding of the liquidity related to daily transactions, which are often relied upon by natural gas market participants to manage day-to-day variations in demand, we can assess how the market liquidity is affected during events that impact the overall North American market and specifically, the Texas market. The section below examines the liquidity impact of five major events impacting the North American and Texas natural gas market that have occurred since 2001.

September 11, 2001

The attacks of September 11, 2001 precipitated a market panic that led to a substantial reduction in Texas market liquidity, with reported volumes bottoming out to approximately 400 MMcf/d on the flow date of September 12, 2001. However, as shown in Figure E5, the reduction in liquidity was very short and the market quickly recovered by the next day, September 13, 2001. In addition, the lack of market liquidity did not result in significant curtailments in supply. Rather, gas continued to flow into the U.S. pipeline network even during the drop in reported transactions.

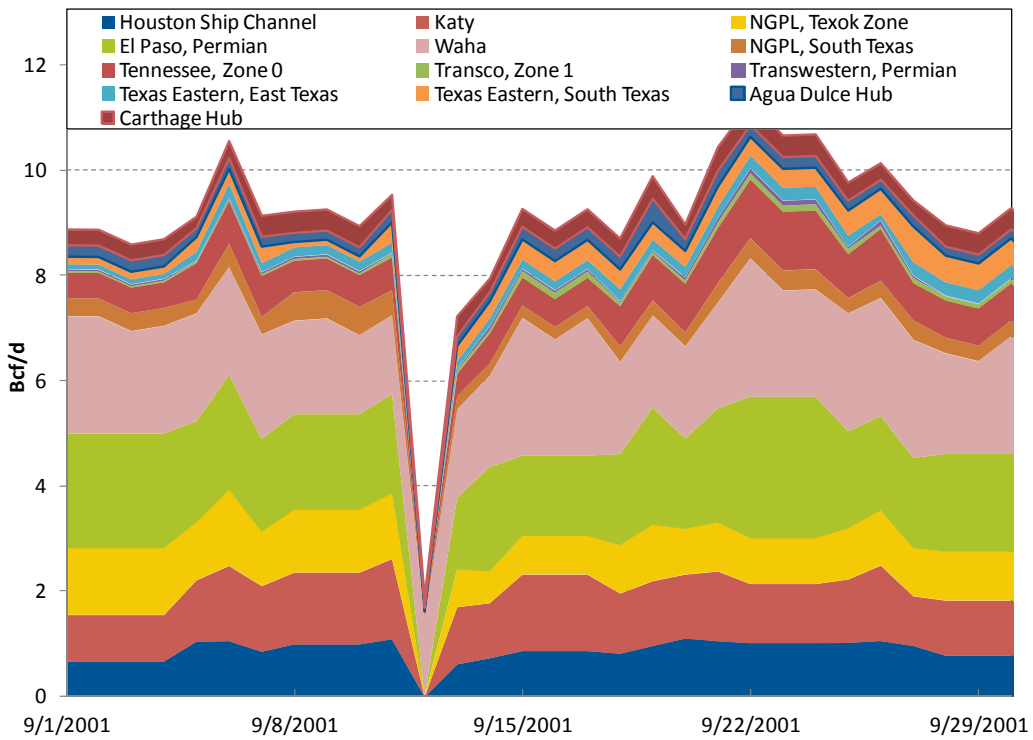


Figure E41: Daily Traded Volumes Reported at Texas Natural Gas Pricing Points: September 2001.

February 2003 Cold Front

Cold weather in early and late February 2003 impacted gas demand and had implications for freezing gas supply. It did not have a meaningful impact on market liquidity for volumes traded at Texas pricing locations (Fig. E6). This implies that a robust and liquid market remained in place for buyers and sellers of gas during this cold front.

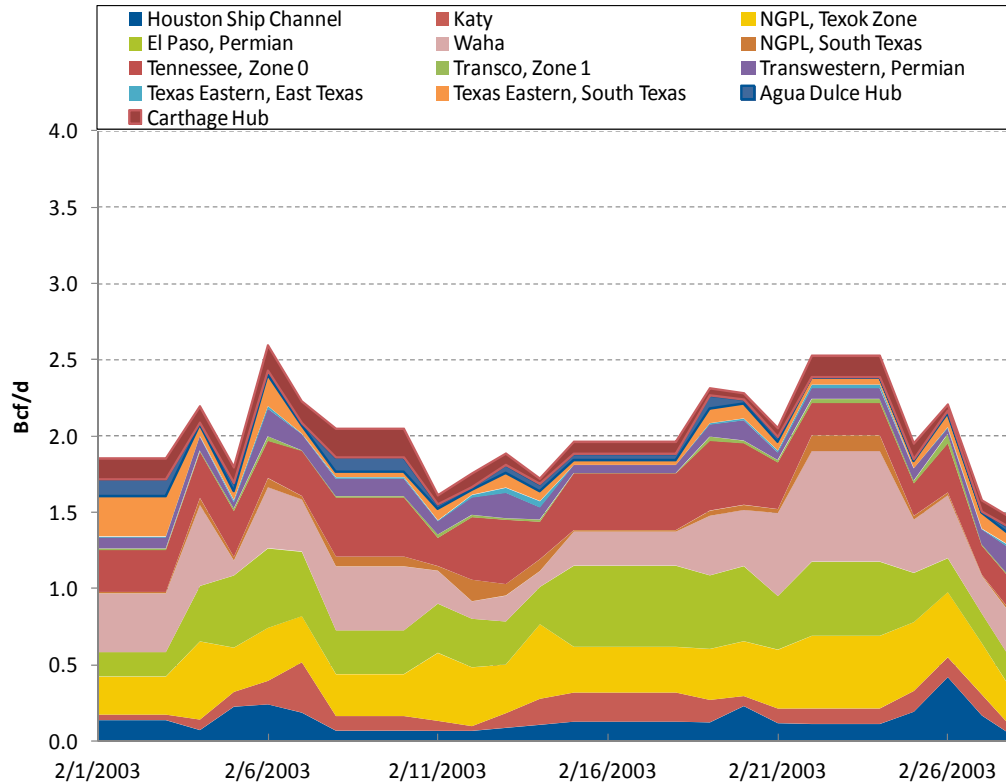


Figure E42: Daily Traded Volumes Reported at Texas Natural Gas Pricing Points: February 2003.

Hurricanes Katrina and Rita (August - September 2005)

The landfall of Hurricane Katrina (late August 2005) had minimal impact to traded volumes and market liquidity. However, Hurricane Rita (mid-September 2005) led to a significant drop in traded volumes in Texas of approximately 1 Bcf/d towards the end of September 2005. This was due in part to the hurricane’s path and the shut-in of offshore production that occurred with Hurricane Rita (especially when compared to minimal supply disruptions / shut-ins during Hurricane Katrina). Traded volumes were especially lower for points in Southeastern Texas (Fig. E7). However, market liquidity was sustained at other locations in Texas. Transactional activity quickly returned to normal patterns by September 28, 2005.

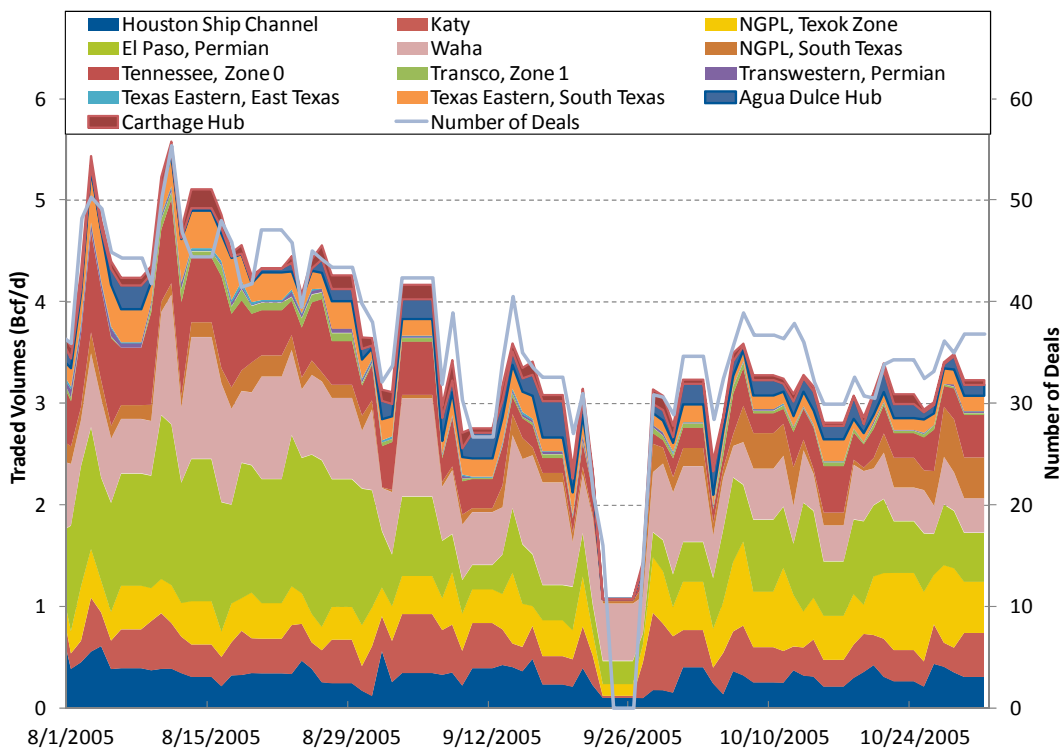


Figure E43: Daily Traded Volumes Reported at Texas Natural Gas Pricing Points: August through October 2005.

Hurricane Ike (September 2008)

Similar to Hurricane Rita, the landfall of Hurricane Ike required a substantial amount of offshore production to be shut-in. In addition, after the hurricane moved onshore, it was discovered that Hurricane Ike created substantial damage to offshore production facilities in its general path. This event led to a significant drop of approximately 3 Bcf/d, in traded volumes in Texas in mid September 2008 (Fig. E8). Traded volumes were especially low for points in South and Southeastern Texas while market liquidity was sustained at locations in West and North Texas. Traded volumes reverted to normal patterns by September 17, 2008 following this disruption.

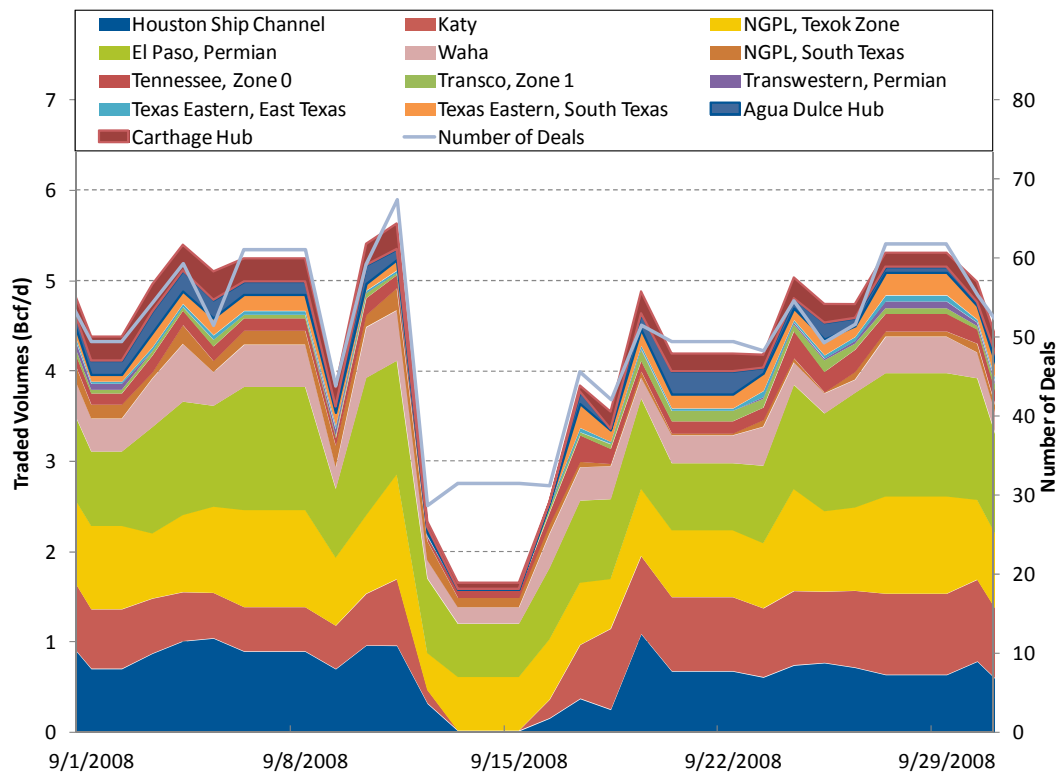


Figure E44: Daily Traded Volumes and Deals Reported at Texas Natural Gas Pricing Points: September 2008

February 2011 Cold Front

Abnormally cold weather experienced in February 2011 had the opposite effect when compared to other cold weather events. Market liquidity for volumes traded in Texas jumped to levels of 5 to 7 Bcf/d during the first week of February (Fig. E9).

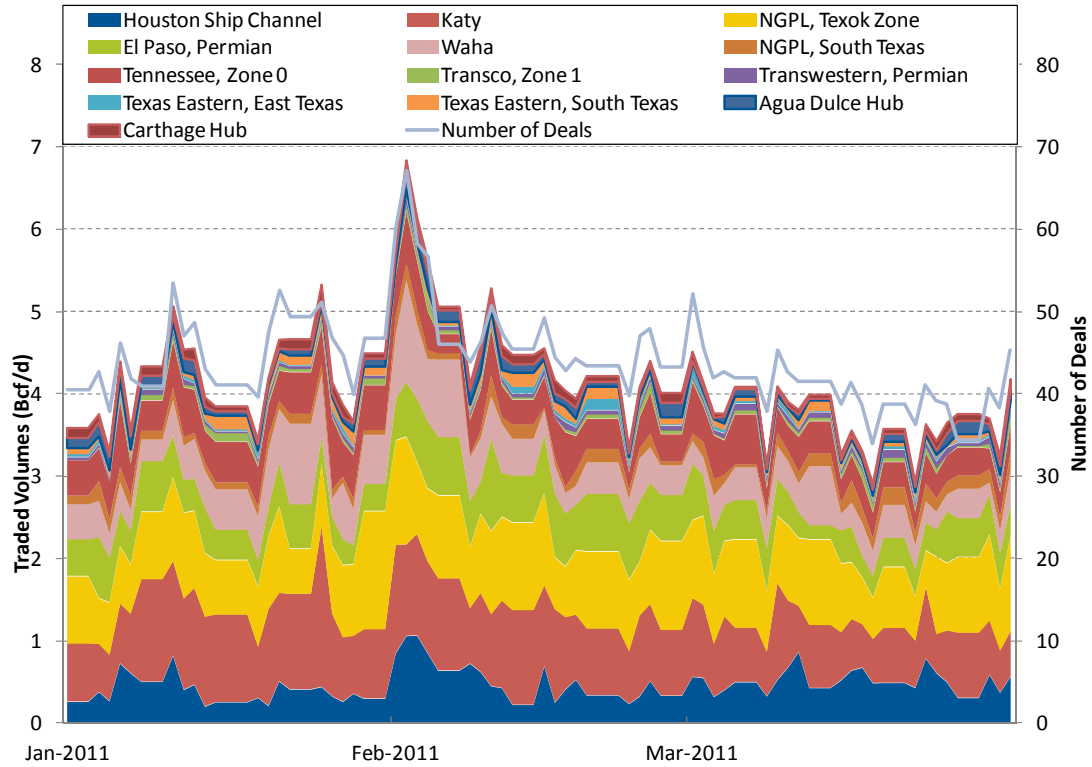


Figure E45: Daily Traded Volumes and Deals Reported at Texas Natural Gas Pricing Points: January through March 2011.

Overall, regulations, industry practices, and market evolution have created a robust and liquid natural gas market in Texas to meet the needs of buyers and sellers. As shown in this Appendix, even during times of stress resulting from unique events, natural gas market activity continued and quickly recovered to pre-event levels. It should also be noted that natural gas continued to flow on pipelines to serve consumers even during periods of lower transactional activity in the market. This indicates that reliance on the short-term natural gas market, for short-term supplies or replacement supplies under term agreements, creates a relatively low risk for gas generators in ERCOT that employ prudent gas procurement practices.

APPENDIX F – DECEMBER 1983 EVENT SIMULATED FOR 2011-2012

December 1983 as a Stress Test. Because historical information shows that freezing weather is the most significant threat to ERCOT’s gas supplies, it is important to understand the magnitude of risk presented by major historical freezing-weather events if the historical based curtailment relationships were applied to the current infrastructure in ERCOT. This analysis examines the cold weather event of December 1983 and its potential impact on natural gas production and electric generation capacity when applied to the current natural gas and electric generation infrastructure within ERCOT’s service region. As with the remainder of this study, our analysis results presented here assume no mitigation from natural gas storage, pipeline line-pack or displacement flows from other regions that would reduce the level of gas supply curtailments and electric generation capacity impacted. Therefore, the risk assessment should be viewed as a conservative scenario to facilitate ERCOT planning.

Many cold winters have affected ERCOT, especially since the 1970s (Figure F46), but the severity usually was greatest for events where freezing temperatures prevailed for many consecutive days. Most events have persisted for only about 2-4 days but in December 1983 the freezing conditions persisted for 11 consecutive days (Figure F47).

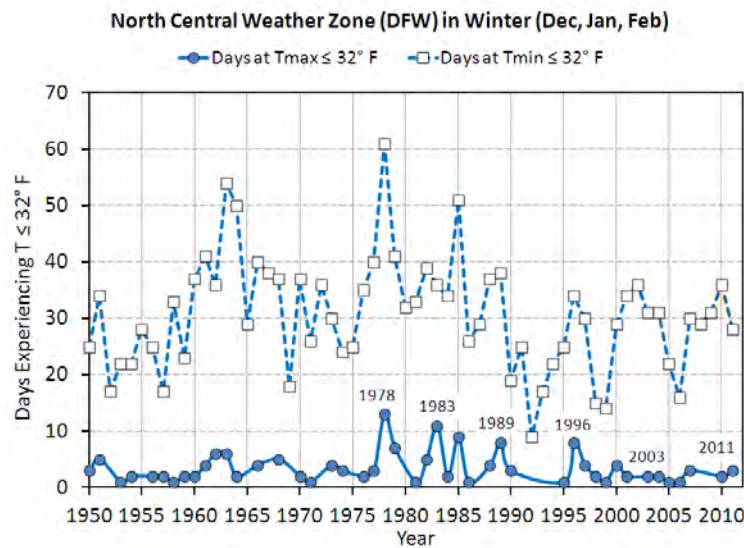


Figure F46. Notably cold winters affecting ERCOT since 1950.

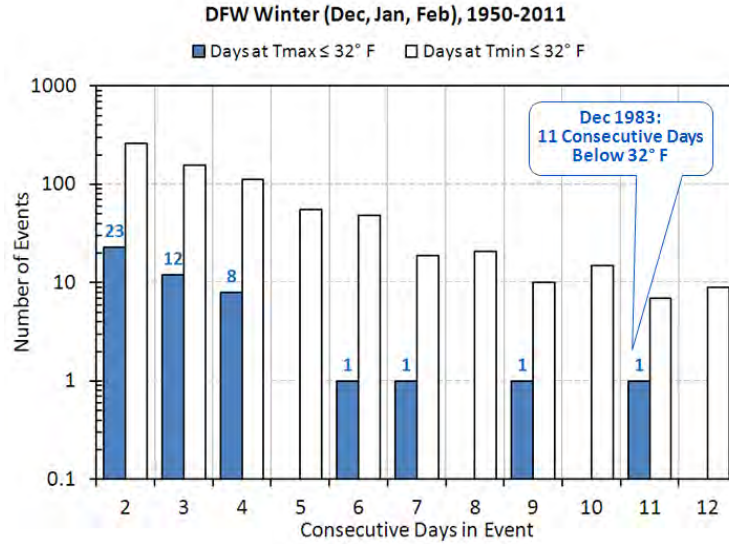


Figure F47. Lengths of freezing-weather events affecting ERCOT.

In north Texas, temperatures remained at or below freezing from December 19 through December 29, 1983 (Figure F48). Furthermore, the distribution of the Arctic air mass in December 1983 also was spread more evenly across ERCOT than in some of the other notable historical freezing-weather events with the possible exception of the shorter December 1989 event (Figure F49).

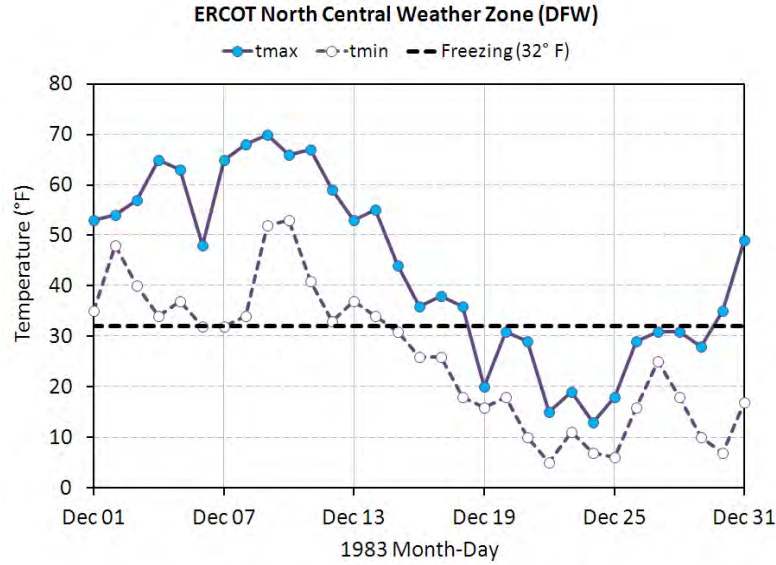


Figure F48. Daily temperatures in north Texas during December 1983

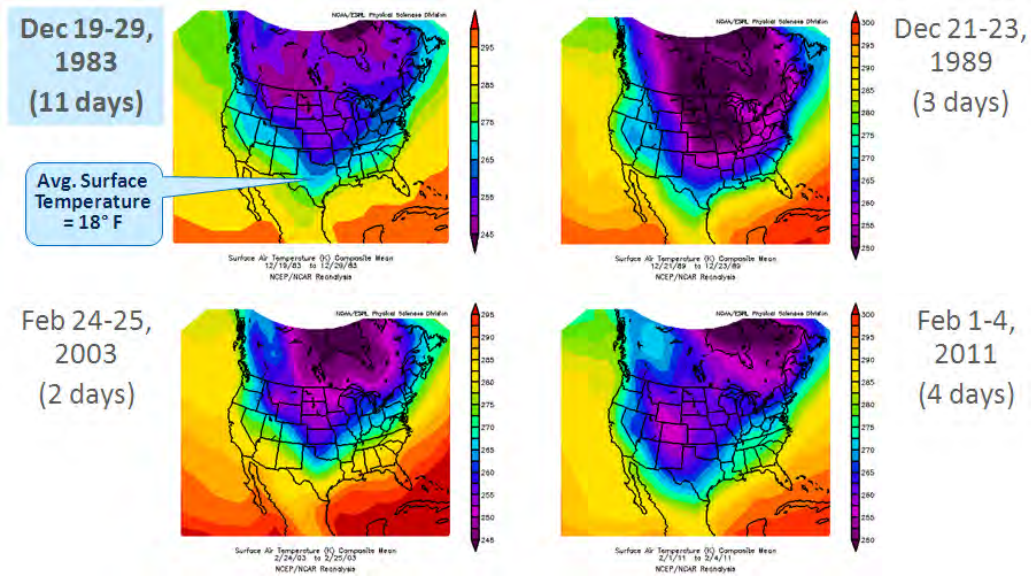


Figure F49. Freezing temperature patterns in major historical events affecting ERCOT.

Analyses Performed. To evaluate the possible consequences of the December 1983 weather conditions applied to the ERCOT natural gas infrastructure of 2011-2012, historical winter weather data were analyzed to derive freezing-weather risk statistics, including likelihood of the December 1983 event in historical context. Additional analyses were performed to impute impacts on ERCOT gas supplies and deliverability under December 1983 weather conditions, including wellhead freeze-offs and resiliency of the gas pipeline infrastructure.

Historical weather data from NCDC were analyzed for five representative Texas weather benchmarks (Figure F50): Dallas (DFW and NBE), Houston (HOU and IAH), San Antonio (SAT), Midland (MAF) and Brownsville (BRO). For each station, probability distribution functions were developed for daily low temperatures and daily average wind speeds during winter (January, February, December) over the years 1950-2011. Wind was included to accommodate possible effects of wind chill³⁹ in contributing to freeze-off effects.

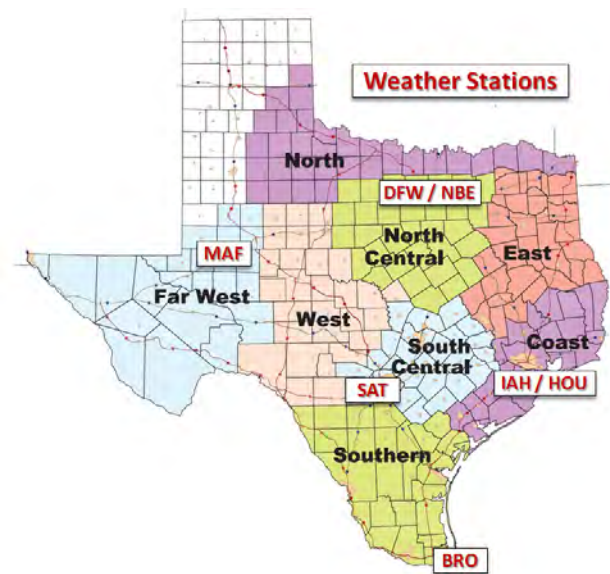


Figure F50. Weather stations used for the December 1983 analyses across ERCOT.

Natural gas production was analyzed for the Barnett Shale (north Texas), Eagle Ford Shale (south Texas) and Haynesville Shale (east Texas) plays using data from the TRRC. Although none of those plays were significant gas producers during 1983, and the information to date concerning production variability due to freezing weather does not include an extreme winter similar to 1983, all are significant within the 2011-2012 infrastructure so it is insightful to understand their possible responses to a prolonged freezing-weather episode as severe as for December 1983. The focus of correlated production-weather analyses was on estimating production losses during recent freezing-weather events.

³⁹ Wind chill is an apparent temperature calculated from wind speed and real physical temperature. It is a theoretical index designed to guide decisions about human exposure to cold environments. Wind chill is only defined for temperatures at or below 50° F and wind speeds above 3 mph. Bright sunshine may increase the wind chill temperature (i.e., make it less severe) by 10-18° F.

<http://www.nws.noaa.gov/om/windchill/>

Pipeline infrastructure data were those compiled by Black & Veatch for use in the GPCM™ equilibrium flow model. Natural gas demand for residential and commercial users was modified to reflect higher heating loads corresponding to the extreme cold weather being modeled. Simultaneously, natural gas supply was reduced to reflect the impact of production well freeze-offs caused by the extremely low temperatures as described below.

Wellhead Freeze-Off Effects. Freezing weather can reduce gas flow at the wellhead through abnormal accumulations of liquids or ice which become problematical only at cold temperatures (Figure F51). The product stream from the well generally contains raw gas mixed with various amounts of water and oil condensates which must be promptly separated before the gas can be placed in a gathering-system pipeline and sent to a processing plant. Direct freeze-off effects include blockage of gas flow through (1) water frozen in the pipe-and-valve tree (“Christmas Tree”) atop the wellhead; (2) water frozen in the scrubber/separator which splits the product streams; (3) natural gas liquids (NGLs) or hydrates condensed before the gas can exit to the gathering system. Indirect freeze-off effects most commonly are breakdowns in the field services needed to keep the wellhead processes operational, including (4a) removal of separated water and oil condensate from limited onsite storage; (4b) replenishment of consumable chemicals (hydrate and corrosion inhibitors) which comprise the first line of gas treatment to prevent condensation in gathering pipelines. Modern wellhead systems include automated SCADA systems which normally are programmed to recognize empty/full tank conditions and shut-off product stream flow at the tree to prevent larger problems of spillage or line clogging. Interruptions to field services commonly are related to access problems created by inclement weather conditions.

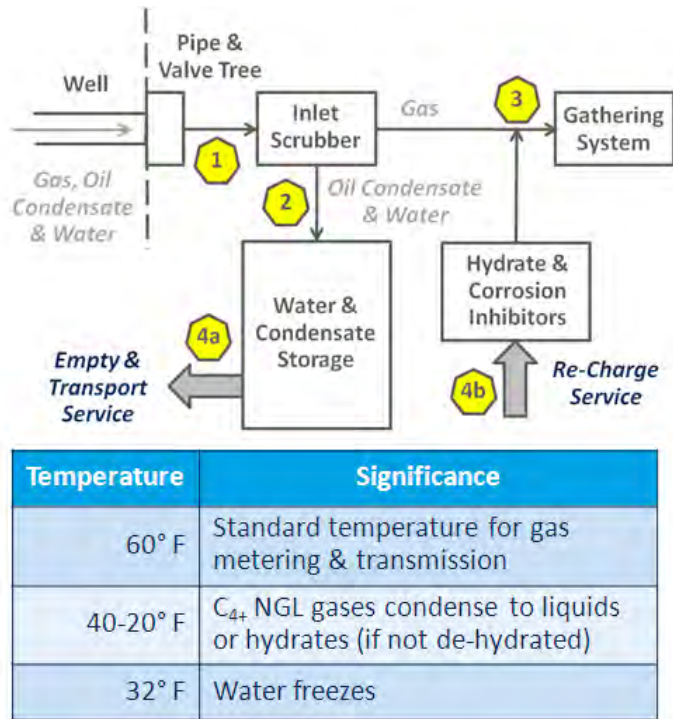


Figure F51. Freeze-off risks at an onshore natural gas wellhead.

Based on principles of thermodynamics, wind chill increases the rate at which an object loses heat to the environment (Figure F52). Under influence of a strong wind, thermal conductive cooling is important whereas under calm conditions cooling is limited by thermal radiation. Nonetheless, the physical low temperature – not wind chill -- ultimately determines whether freezing occurs.

Wind chill values in December 1983⁴⁰ varied regionally across ERCOT (Figure F53) and were included in analyses which sought correlations between freezing-weather attributes and wellhead freeze-off production losses. But based on the limits of the theoretical definition, calculated wind chill values higher than 50° F are immaterial and indeed wind chill values higher than 32° F are mostly irrelevant. So for December 1983 wind chill values for dates earlier than about December 13 are uninformative.

⁴⁰ Daily extreme wind chill values were calculated from average wind speed and the minimum physical temperature for the day.

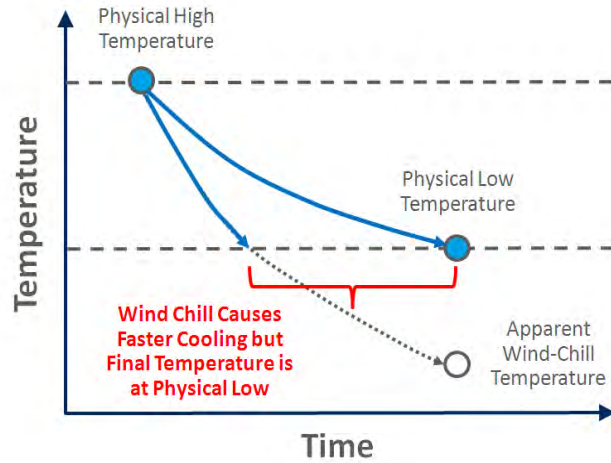


Figure F52. Significance of physical temperature relative to wind chill.

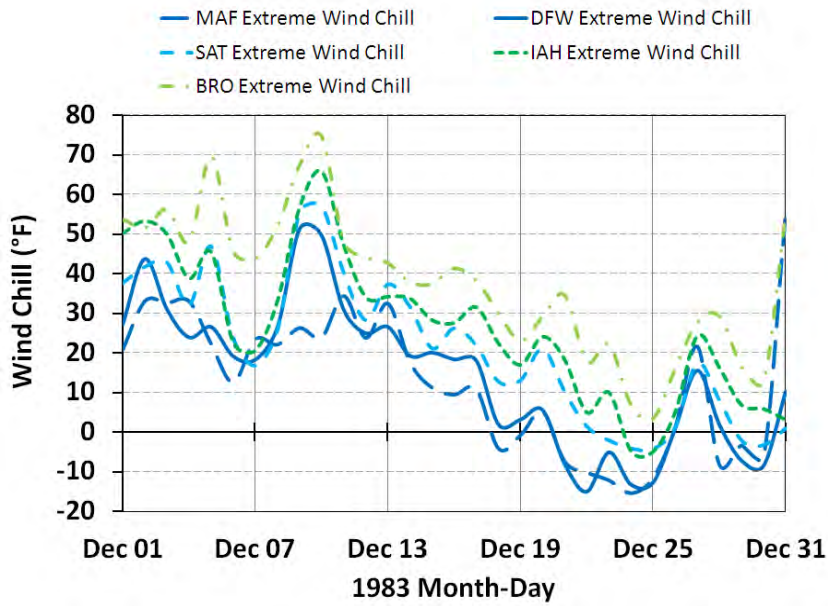


Figure F53. Daily wind chill values across ERCOT during December 1983.

Freezing of water and condensation of NGLs are different problems which vary according to the composition of the product stream from each well. Associated gas which is produced from oil wells generally will flow greater proportions of water as the well ages. Therefore, older “conventional” gas wells tend to be at greater risk of water-related freeze-offs.

“Unconventional” gas, such as from shales or other tight formations, will be at comparatively greater risk of water-related freeze-offs if the wells are relatively young (i.e., completed within the last few months) because the flow-back of hydraulic-fracturing water probably still is in progress. NGL contents will be at risk for condensate formation both in conventional and unconventional wells and the risks will increase as the NGL contents increase. Therefore, risks of wellhead freeze-offs are expected to exist for all types of gas fields although specific risks for any particular field will depend on the types and ages of the wells in the field.

Gas production data show that the February 2011 freezing-weather event involved production losses for the Barnett Shale, Eagle Ford Shale and Haynesville Shale fields (Figure F54). Furthermore, the relative proportions of the production losses scale according to the relative NGL contents of the respective fields. Namely, the rich-gas Eagle Ford was most affected and the dry-gas Haynesville was least affected.

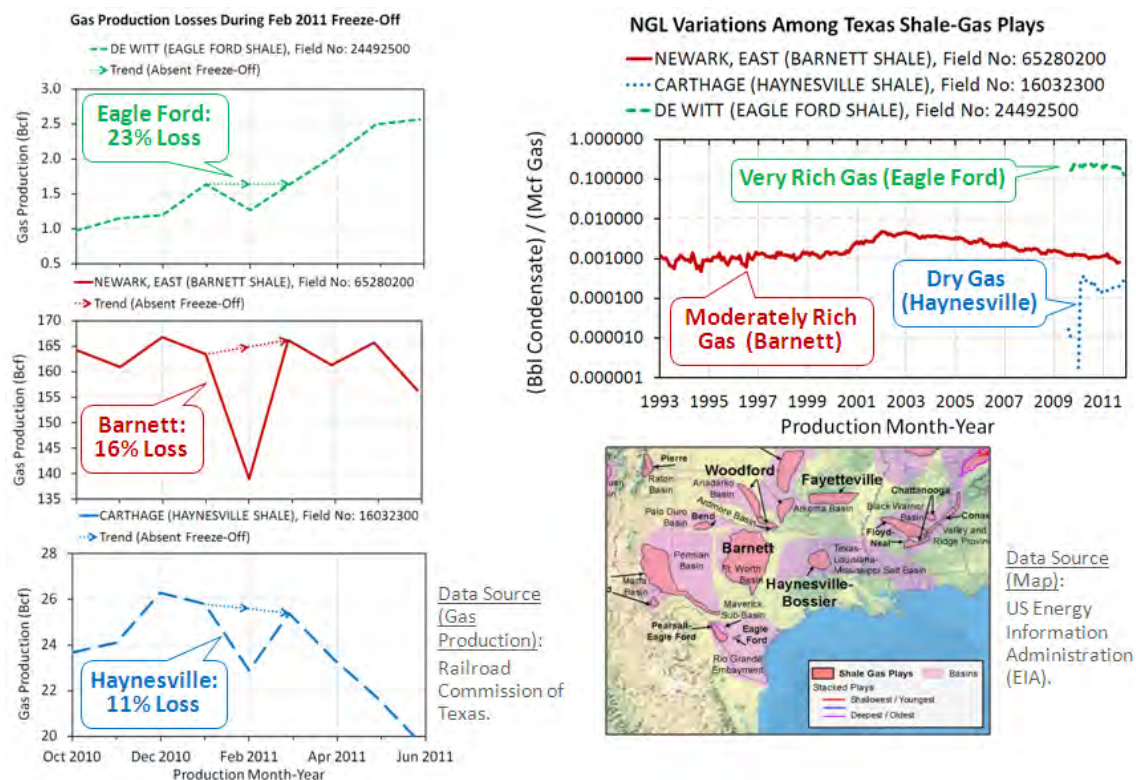


Figure F54. Natural gas production losses during the February 2011 freezing-weather event.

The Barnett Shale represents the major gas source in the 2011-2012 timeframe with the longest baseline of production data. Accordingly, empirical models for production losses during freezing-weather events were focused on the Barnett Shale data with the premise that the Barnett loss functions can be used as proxies for other gas fields which supply ERCOT.

Empirical production-loss curves were developed both for physical temperature and for wind chill using historical production and weather data (Figure F55). Both linear and non-linear regressions were calculated based on analysis of historical production losses versus historical weather for the six major freezing-weather events captured in the ERCOT Operator Logs (2002-2011; solid dots in Figure F55). Loss functions for wind chill are statistically stronger (higher R² values) but loss functions for physical temperature predict the highest production losses. Both for temperature- and wind chill-based functions, the non-linear models appear to be statically more robust (higher R² values). Therefore, to estimate “worst case” freeze-off losses, the model chosen was the non-linear Production Loss vs. Physical Low T(F) from the left-hand chart in Figure F55.

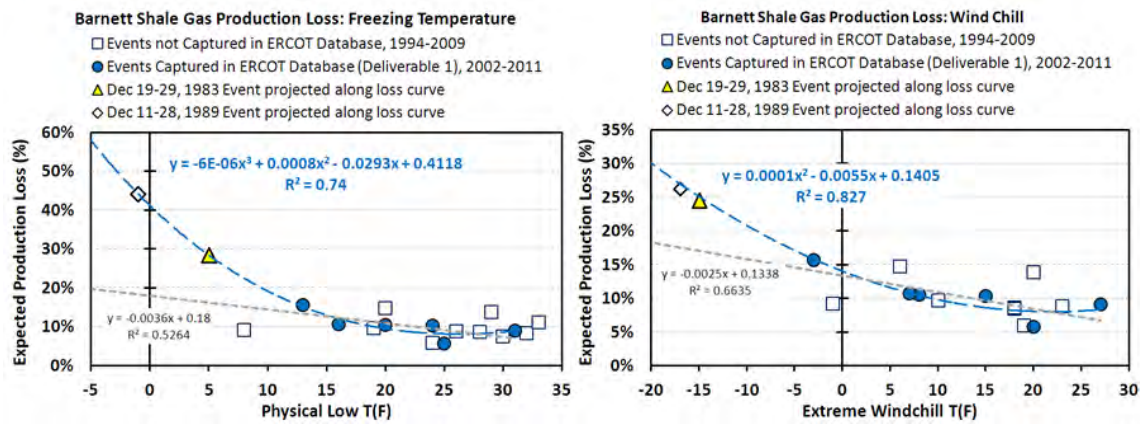


Figure F55. Empirical production-loss models based on production-weather data regressions.

In applying the freeze-off loss function model, adjustments were made for relative NGL contents of different gas fields. The adjustments comprised scalars applied to the production loss calculated from the temperature-based loss function using one of three values: Average NGL content (Barnett) = 1.0; rich gas or high NGL content (Eagle Ford) = 1.4; dry gas or low NGL content (Haynesville) = 0.7.

The gas sources embedded in the GPCM™ model for ERCOT included all ten of the TRRC Districts plus specific plays of note, including Barnett, Eagle Ford and Haynesville. For each day of the December 19-29, 1983 event (Figure F48), wellhead production losses from freeze-off were calculated for daily gas production expected in 2011-2012 from each TRRC District and each featured field. The index temperature applied to each calculation was that reflected by the geographically appropriate weather station (Figure F50). The summation of all production losses by day, relative to normal anticipated production, indicated the day-by-day wellhead supply loss through the course of the 11-day event (Figure F56).

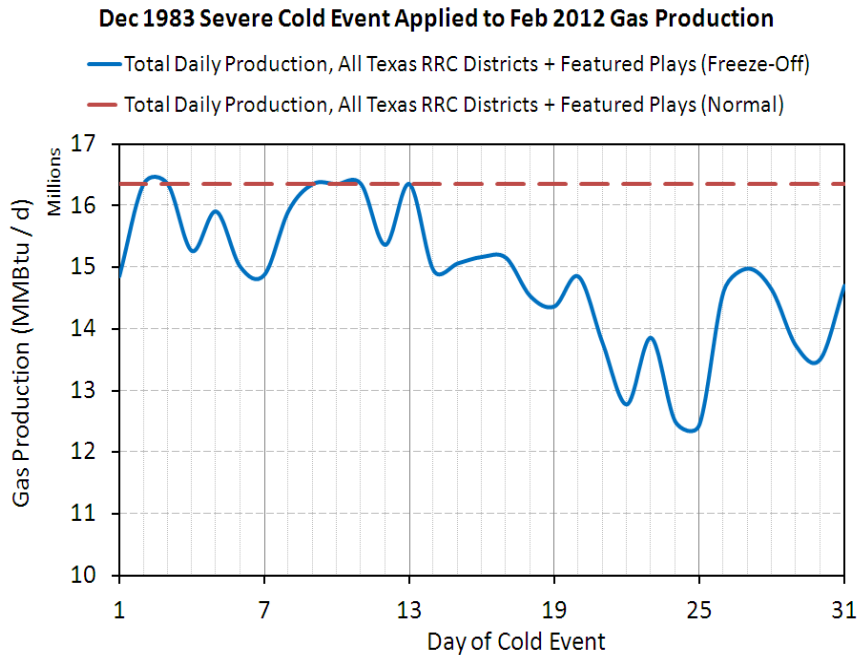


Figure F56. Theoretical gas-production losses in Feb 2012 under Dec 1983 weather conditions.

On the model day with the most severe sub-freezing temperatures (December 25, 1983), the theoretical impacts of wellhead freeze-offs in February 2012 would equate to an available daily gas production of 12.4 million MMBtu, compared with a normal expected production of 16.4 million MMBtu, or an apparent daily supply loss of 23.9%. For the 11-day model period (December 19-29), the smallest projected daily loss is 8.4% and the average daily loss is 15.2%. Of course, all of the aforementioned figures are the projected losses from fresh wellhead supplies and they do not take into account other sources of back-up supplies such as underground storage or pipeline line pack.

Statistical Likelihood of the December 1983 Event. Results of the stress test described above show that repetition of the extreme freezing-weather event of December 1983 could seriously impact availability of wellhead-produced gas required by the current power-generation portfolio in ERCOT. But because the risk assessment must consider not only the consequences of an event but also the likelihood of the event, it is important to understand that the subject event was one of very low likelihood.

Based on analysis of historical weather data for 1950-2011, Figure F57 shows daily winter freeze-risk models for representative points across ERCOT, including Midland (MAF), Dallas-Ft. Worth (DFW), San Antonio (SAT), Houston (HOU) and Brownsville (BRO). Risks of severe freezing (for example, 20° F or colder) are greatest for northern and western parts of ERCOT with daily probabilities of about 3-7% on any given winter day. Risks of ≤ 20° F temperatures are lower elsewhere but still can approach 1% in south-central and coastal parts of ERCOT. The December 1983 event was a statistically unlikely occurrence since its magnitude represented a daily risk of only about 0.02-0.5%, depending on the region of Texas chosen as the risk location (Figure F57).

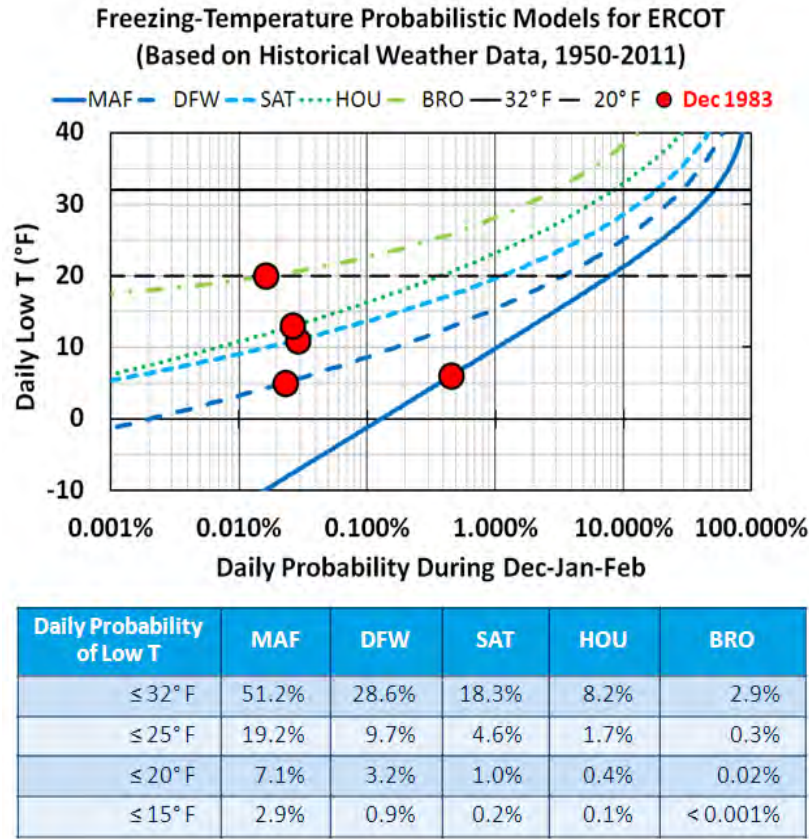


Figure F57. Daily winter freeze risks across ERCOT compared with December 1983 event.

Figure F58 shows daily winter wind-risk models for the same representative points across ERCOT as shown for freezing temperature in Figure F57. When the role of wind is addressed in freezing-weather events, a significant milestone is that a sustained wind of 20 miles per hour applied to a physical temperature of 32° F translates to an apparent wind chill temperature of 20° F which is a key physical temperature for hard-freeze effects. So even though physical temperature, rather than wind chill, is the ultimate determinant of whether freezing occurs, a strong wind chill factor can accelerate cooling until the physical low temperature is reached. Historical weather data show that, even though wind gusts can be stronger, sustained winds across ERCOT during winter are less than 20 mph for 95-99.9% of the time on any given winter day. During the severe freezing-weather event of December 1983, winds were skewed toward the high end of the risk curves, comprising wind speeds at the 78th-97th percentile marks (Figure F58) or about 7-12% likely to occur on any given winter day. Altogether the risk model results confirm that extremely low physical temperatures, rather than wind chill indexes, are the most important fundamentals in freezing-weather risks. Therefore, the most important risk attribute associated with the December 1983 event was that based on extreme low temperatures as discussed above.

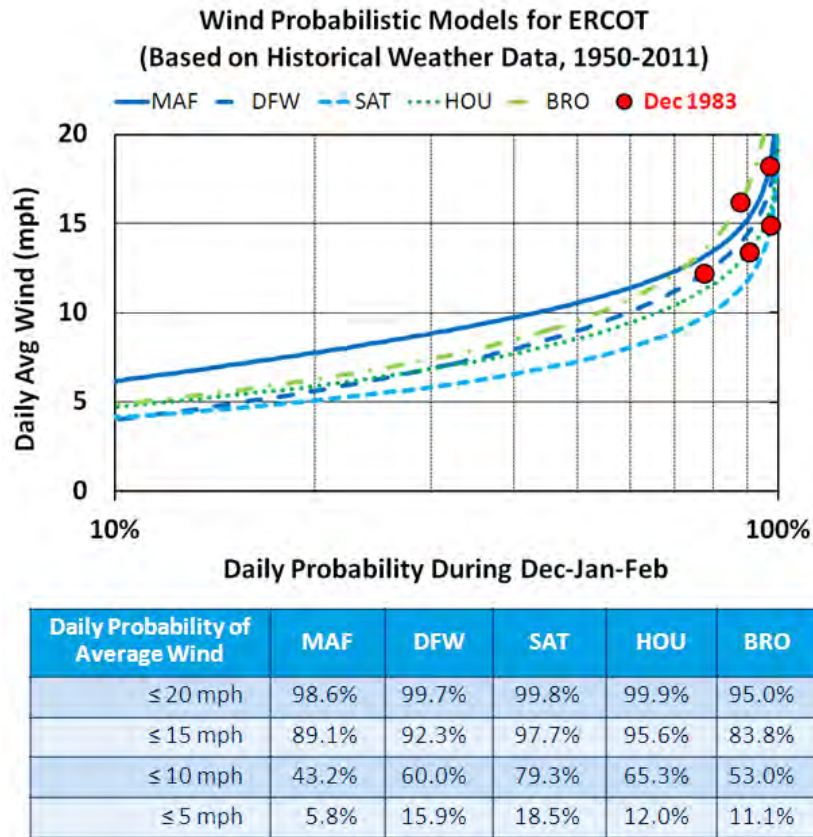


Figure F58. Daily winter wind risks across ERCOT compared with December 1983 event.

Assuming that the future winter climate affecting Texas is described by the historically-based statistical models developed for this analysis, the probability that the extreme low temperatures of December 1983 event will be repeated in any given winter is no more than 0.5% and more likely closer to 0.02%.

The probability that an extreme freezing-weather event will persist for 11 consecutive days, as occurred in December 1983, can be estimated from the data in Figure F47 which shows that the December 1983 event was one of 47 extreme-freezing events ($T_{max} \leq 32^\circ F$) which lasted 2-11 consecutive days. Those events altogether involved 162 days from a historical sample of 5,564 winter days. Accordingly, an 11-consecutive-day event of the severity of December 1983 represents a probability of only 0.06%⁴¹.

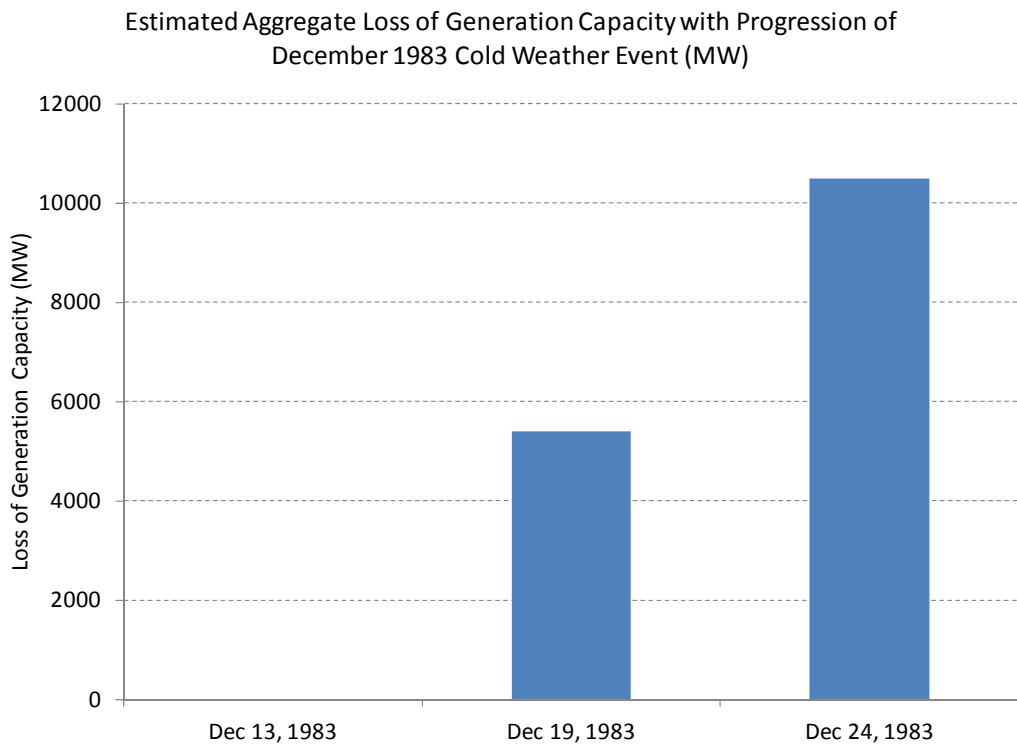
On balance, the probability of occurrence of the December 1983 event in any given winter can be viewed as an indicative value of 0.1% or less.

Evaluation of Pipeline Deliverability. In the GPCM™ model for ERCOT, the production losses calculated from the freeze-off loss function were used as input information to modify available gas supplies while the heating demand associated with residential and commercial sector was increased to reflect the exceptionally cold weather. Our analysis indicated that,

⁴¹ $(162/5,564) * (1/47) = 0.000619$

overall, the natural gas pipeline capacity between the different regions within Texas is adequate to meet the higher natural gas demand during the extreme cold weather scenario. The fundamental supply-demand model utilized for our analysis seeks equilibrium by displacing natural gas from other regions as needed to meet ERCOT demand and rebalancing the natural gas network. Localized pipeline curtailments may be experienced within a given region depending on the constraints of specific delivery systems.

Potential Loss of Generation Capacity. Black & Veatch estimated the loss in electric generation capacity associated with the projected loss in natural gas production caused by projections of production well freeze-offs. In order to do this, we assumed that residential and commercial natural gas needs are met first during period of wellhead production freeze-offs and lower supply. This is consistent with the TRRC’s curtailment policies that places these loads at a higher priority for supply than industrial and electric generation needs. Industrial and power generation demand are both assumed to be impacted by the decrease in natural gas supply and in the ratio of their respective demands for natural gas. Figure F14 shows the potential loss in electric generation capacity within the ERCOT service region.⁴² It should be noted that this analysis does not assume any mitigation in effect that could potentially reduce the loss in electric generation capacity. In reality, various mitigation measures would be available and effective within the natural gas market including access to natural gas storage, pipeline line-pack and displacement of flows intended for other markets. These and other mitigating measures would decrease the effective loss of natural gas supply to electric generators and consequently reduce the gas-fired electric generation capacity affected.



⁴² To convert gas (MMBtu/d) to power generation (MW), we assumed a heat rate of 7.5 Dth/MWh.

Figure F59. Estimated Aggregate Loss of Generation Capacity

GLOSSARY

AGA (the American Gas Association): AGA is an organization focused on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas.

Bcf/d (Billion cubic feet per day): Bcf/d is the commonly used unit of measurement for large production rates of natural gas.

DOT (US Department of Transportation): The Department of Transportation was established by an act of Congress on October 15, 1966. DOT is tasked with serving the United States by ensuring a fast, safe, efficient, accessible and convenient transportation system.

EBB (Electronic Bulletin Board): EBB refers to Pipeline Electronic Bulletin Boards which regulated natural gas pipelines are required to maintain in order to make available key information about their operations to the public. Pipeline EBBs contain publicly-available information such as pipeline capacity, gas quality, index of customers, notices, tariffs, pipeline imbalances, and pipeline system maps.

EMP (The Energy Market Perspective): EMP is the Black & Veatch's integrated view of natural gas and power markets across North America, and the northern portion of Baja California, Mexico, that is electrically interconnected to the U.S.

ERCOT (The Electric Reliability Council of Texas): ERCOT is the independent system operator for Texas and manages the flow of electric power to 23 million Texas customers - representing 85 percent of the state's electric load.

FERC (The Federal Energy Regulatory Commission (FERC): The Federal Energy Regulatory Commission (FERC) is the United States federal agency that regulates, monitors and investigates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas (LNG) terminals and interstate natural gas pipelines as well as licensing hydropower projects.

GOM (Gulf of Mexico): GOM is a prolific natural gas- and oil-producing area bordered by the United States to the north and east (Florida, Alabama, Mississippi, Louisiana, Texas), and five Mexican states to the south and west.

HDD (Heating Degree Day): HDD measures the demand for energy needed to heat a residence or business. HDD is calculated as the difference between the daily average temperature and 65° Fahrenheit for every day where the daily average was colder than the 65° F reference. Although choice of reference temperature sometimes varies with geography, the 65° F reference was used in this study both for Texas and locations outside Texas.

IMM (Integrated Market Modeling): IMM is the Black & Veatch modeling process to prepare its long term view on energy markets. Black & Veatch draws on a number of commercial data sources and supplements them with its own view on several key market drivers, for example, power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and gas pipeline expansion.

IMP (Integrity Management Plan): IMP is the plan developed by Pipeline and Hazardous Safety Administration (PHMSA) to provide information about the PHMSA Rules on Pipeline Integrity Management.

MAOP (maximum operating pressure): MAOP is the highest pressure at which a pipeline may be operated under Department of Transportation (DOT) regulations.

MMBtu/d (Dekatherm per day): MMBtu/d is the commonly used unit of measurement for the heat content of natural gas. One dekatherm (sometimes also spelled “dekatherm”) equals one MMBtu.

MMcf/d (Million cubic feet per day): It is the commonly used unit of measurement for large production rates of natural gas.

NCDC (the National Climatic Data Center): The official repository for climate data acquired and the US government. Data collected by the National Weather Service, U.S. Navy, U.S. Air Force, the Federal Aviation Administration, and meteorological services around the world, are housed at the NCDC which is the largest active archive of weather data in the world.

NETL (the National Energy Technology Laboratory): The National Energy Technology Laboratory (NETL), part of DOE’s national laboratory system, is owned and operated by the U.S. Department of Energy (DOE). NETL supports DOE’s mission to advance the national, economic, and energy security of the United States and implements a broad spectrum of energy and environmental research and development (R&D) programs.

NHC (National Hurricane Center): NHC is a component of the National Centers for Environmental Prediction to issue watches, warnings, forecasts, and analyses of hazardous tropical weather and increase understanding of these hazards. In collaboration with the NCDC, NHC also functions as the repository for historical data on tropical cyclones in the eastern Pacific and Atlantic basins.

NOAA (the US National Oceanic and Atmospheric Administration): NOAA is a federal agency focused on the condition of the oceans and the atmosphere. It is the parent organization of NCDC, NHC, SPC and other weather-focused organizations of the US government.

NGL (Natural Gas Liquid): Natural gas liquids are defined as the heavier hydrocarbons (two or more carbon atoms in the molecule) comprising ethane, propane, butane, and natural gasolines, which are found in natural gas. NGLs must be separated through the process of absorption, condensation, adsorption, or other methods in gas processing or cycling plants before the residual (methane-rich) gas can be transported in natural gas pipelines.

Outlier: An outlier is a member of a sample which is conspicuously different from other members of the sample. There is no consensus definition of “outlier” although the term is used widely in reports involving statistical analysis. In experimental science, an outlier often is dismissed as the result of unexplained procedural error or tagged as evidence that the sample was drawn from more than one population. For the current study, “outlier” is used to describe a point on the long tail of a PDF, i.e., an event with very low statistical probability of occurrence.

PDF (Probability Distribution Function): PDF is a mathematical description of the probability of occurrence of each of multiple outcomes within a family of possibilities. It usually is portrayed as a table or graph which shows cumulative probability versus possible value of an outcome. An empirically-derived PDF is a probability model which is based on historical data.

PHMSA (Pipeline and Hazardous Safety Administration): PHMSA is operated by the Department of Transportation's (DOT) and it administers the Department's national regulatory program to assure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline.

SPC (Storm Prediction Center): SPC is part of the National Weather Service and the National Centers for Environmental Prediction (NCEP) to provide timely and accurate forecasts and watches for severe thunderstorms and tornadoes over the contiguous United States. The SPC also monitors heavy rain, heavy snow, and fire weather events across the U.S. and issues specific products for those hazards. In collaboration with the NHC, SPC also serves as a repository for historical data on severe weather.

Undifferentiated: The choice of keeping a sample whole for input into an analysis rather than dividing it into sub-samples for separate analyses. Differentiation (sub-division) is acceptable if the sub-samples are believed to be fundamentally different from each other and if the sub-samples remain large enough for statistically meaningful analyses. For example, in this study, curtailments attributed to freezing weather could be conceived as including sub-categories of (a) wellhead freeze-offs, (b) infrastructure failures or (c) contractual provisions. But attempts to sub-divide created sub-samples which were too small to support rigorous statistical analyses.

TRRC (the Railroad Commission of Texas): The Railroad Commission of Texas is the state agency that regulates the oil and gas industry, gas utilities, pipeline safety, safety in the liquefied petroleum gas industry, and surface coal and uranium mining.